ENVIRONMENTAL IMPLICATIONS OF COAL GASIFICATION/LIQUEFACTION TECHNOLOGIES IN CANADA

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FOR: WATER POLLUTION CONTROL DIRECTORATE
ENVIRONMENTAL PROTECTION SERVICE
ENVIRONMENT CANADA

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LETTER OF TRANSMITTAL

April 7, 1983

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Attention: Mr. Wayne S. Richardson, P.Eng.

Subject: Environmental Implications of Coal Gasification/ Liquefaction Technologies in Canada.
DSS File No. KE204-1-0375
DECS File No. 490

Dear Wayne,

Dearborn Environmental Consulting Services is pleased to submit our final report entitled "Environmental Implications of Coal Gasification/Liquefaction Technologies in Canada". In our submission, we have reviewed coal conversion technology development and the current status of these technologies in commercialization programs and installations around the world. Selected technologies likely to be utilized in near-term coal conversion plants in Canada have been thoroughly analyzed from available information in terms of their air, liquid, and solid waste discharges. Coal conversion wastewater pollutant control technology and overall water management options, identified as key environmental concerns, have been reviewed and discussed in the Canadian context.

In addition to the above review, a laboratory investigation has been conducted on minimum severity solvent extraction pretreatment of H-Coal process sour water followed by bio-oxidation treatment. The feasibility of drastically reducing extraction

solvent requirements and by-product phenols generation, while maintaining adequate wastewater contaminant control, has been indicated in this work.

Finally, the conclusions of the overall study and recommendations to improve the characterization and control of pollutants emanating from coal conversion processes, in light of unique Canadian conditions, have been included.

It has been a pleasure to conduct this study and we look forward to working with you again sometime in the future.

Yours truly,

David N. Young
Project Manager

DNY/ji

Encl.

c.c.: Mr. J. Shaw

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TABLE OF CONTENTS

		PAGE
1.	EXECUTIVE SUMMARY	1
2.	INTRODUCTION	3
3.	REVIEW OF PROCESS TECHNOLOGY	7
	3.1. Coal Conversion Process Routes	7
	3.2. History and Present Status of Coal Conversion Technology	9
	3.3. Description of Selected Processes	12
	3.3.1. SASOL-SYNTHOL (SASOL II) Process	12
	3.3.2. Ruhrkohle/Ruhrchemie Texaco Gasification	14
	3.3.3. H-Coal Process	16
	3.3.4. Lurgi Ruhrgas Flash Pyrolysis Process	17
	3.4. Comparison of Canadian Coals With Selected Process Coal Feedstocks	19
4.	SOLID, AIR, AND LIQUID WASTESTREAM CHARACTERIZATION	21
	4.1. Solid Waste Characteristics	26
	4.1.1. SASOL-SYNTHOL (Hat Creek) Solid Wastes	26
	4.1.2. R/R Texaco-Mobil MTG Process Solid Wastes	29
	4.1.3. H-Coal Process Solid Wastes	32
	4.1.4. Lurgi Ruhrgas Pyrolysis/Power Generation Solid Wastes	36
	4.2. Atmospheric Emissions	38
	4.2.1. SASOL-SYNTHOL Process Atmospheric Emissions	38
	4.2.2. Ruhrkohle/Ruhrchemie Texaco-Mobil MTG Atmospheric Emissions	40
	4.2.3. H-Coal Atmospheric Emissions	41
	4.2.4. Lurgi Ruhrgas Pyrolysis/Power Generation Atmospheric Emissions	43
	4.3. Wastewater Characteristics	45
	4.3.1. SASOL-SYNTHOL (Hat Creek) Aqueous Wastes	45
	4.3.2. R/R Texaco-Mobil MTG Aqueous Wastes	50
	4.3.3. H-Coal Process Aqueous Wastes	54
	4.3.4. Lurgi Ruhrgas Pyrolysis/Power Generation Aqueous Wastes	58

TABLE OF CONTENTS (continued)

5. COAL CONVERSION WASTEWATER TREATMENT TECHNOLOGY 59

5.1. Physical/Chemical Treatment 60

5.1.1. Gravity Separation Processes 60
5.1.2. Filtration 61
5.1.3. Dissolved Gas Removal/Ammonia Recovery 61
5.1.4. Solvent Extraction 63
5.1.5. Chemical Oxidation 65
5.1.6. Tertiary Dissolved Organic and Inorganic Species Removal 67

5.2. Biological Treatment 71

5.2.1. Activated Sludge Process 71
5.2.2. Activated Sludge/Powdered Activated Carbon Process 73

5.3. Water Reuse Considerations 76

6. COAL CONVERSION WASTEWATER TREATABILITY STUDY 78

6.1. Influence of Phenolic Compounds on Wastewater Treatability 78
6.2. Coal Conversion Wastewater Treatability Study 81

6.2.1. Extraction Solvent Selection 81
6.2.2. Experimental Procedure 83

6.3. Experimental Results 88

6.3.1. Phase I Batch Solvent Extraction 88
6.3.2. Shake Flask Biodegradability Study - Phase I 89
6.3.3. Batch Solvent Extraction and Biotreatability - Phase II 90
6.3.4. Summary 92

7. CONCLUSIONS AND RECOMMENDATIONS 94

7.1. Conclusions 94
7.2. Recommendations 96

REFERENCES 98

APPENDICES

LIST OF TABLES

Table 3-1	Comparative Analysis of Hat Creek and South African (SASOL Feedstock) Coal.
Table 3-2	Comparative Analysis of Devco Sydney Coal and Illinois No. 6 Coal.
Table 3-3	Analysis of Alberta Highvale Sub-Bituminous B Coal.
Table 4-1	SASOL-SYNTHOL (Hat Creek) Solid Wastes Generation.
Table 4-2	Elemental Composition of Ash Produced by Gasification of Various Coals in Lurgi Gasifiers.
Table 4-3	Percentage of Trace Elements in Feed Coal Retained With Discharge Lurgi Ash.
Table 4-4	Power Plant Bottom and Fly Ash Composition (Hat Creek Coal).
Table 4-6	Comparative Performance of German and U.S. Texaco Process Pilot Plants Processing Illinois No. 6 Coal.
Table 4-7	Summary of Solid Waste Emissions from R/R Texaco-Mobil MTG Process.
Table 4-8	Texaco (Montebello) Gasifier Slag Analysis.
Table 4-9	Solid Waste Characteristics and Quantities for the H-Coal Breckinridge Project.
Table 4-10	Trace Elements Determined in PDU Vacuum Residuum Bottoms (Illinois No. 6 Coal).
Table 4-11	Production Rates and Carbon Contents of Slag and Soot for Texaco Gasification of H-Coal Liquefaction Residues.
Table 4-12	Power Plant Bottom and Fly Ash Composition (Devco Sydney Coal).
Table 4-13	Power Plant Bottom and Fly Ash Composition (Highvale B Sub-Bituminous Coal).
Table 4-14	Atmospheric Emissions Summary for SASOL-SYNTHOL Plant with Emission Controls.
Table 4-15	Characteristics of Atmospheric Emissions from a SASOL-SYNTHOL Plant.
Table 4-16	Storage Tank Emissions for a SASOL-SYNTHOL Plant.

LIST OF TABLES (continued)

Table 4-17	Particulate Emissions Summary for a SASOL-SYNTHOL Plant.
Table 4-18	Atmospheric Emissions Summary for an R/R Texaco-Methanol Synthesis Plant.
Table 4-19	Characteristics of Gas Flows and Atmospheric Emissions from R/R Texaco-Methanol Synthesis Plant.
Table 4-20	Projected Major Emissions Summary for the H-Coal Breckinridge Project.
Table 4-21	Summary of Proposed Air Pollution Controls for the H-Coal Breckinridge Project.
Table 4-22	Emergency Flare Systems Emission Summary for H-Coal Breckinridge Project.
Table 4-23	Characteristics of Lurgi Gas Liquors.
Table 4-24	Performance of Phenolsolvan/Ammonia Stripping Pretreatment at SASOL.
Table 4-25	Phenol Composition Breakdown for Raw SASOL I Lurgi Gas Liquor.
Table 4-26	Characteristics of Raw and Processed Wastewater from the Lurgi Dry Ash Process Plant at Sasolburg, South Africa.
Table 4-27	Trace Elements in Lurgi Gas Liquor After Tar/Oil Separation (U.S. Coals).
Table 4-28	Trace Element Balance for Lurgi at SASOL.
Table 4-29	Estimated Solubility of Elements in Lurgi Ash from Gasification of Dunn County, North Dakota Lignite.
Table 4-30	Characteristics of Rectisol Methanol-Water Still Bottoms for Lurgi Facility at SASOL, South Africa.
Table 4-31	Control Limits for Cooling Tower Circulating Water Composition.
Table 4-32a	Preliminary Estimates of Combined Ash Leachate Quality.
Table 4-32b	Projected Low Grade Coal and Coal Leachate Characteristics.
Table 4-33	Texaco Gasifier Wastewater Quality.

LIST OF TABLES (continued)

Table 4-34 Generation of Aqueous Waste from the Mobil-MTG Process.

Table 4-35 Characteristics of De-Ionized Water Leachate from Texaco Slag.

Table 4-36 Coal Pile Drainage Sample from Lingan Generating Station.

Table 4-37 Sources of Utility Wastewater and Their Anticipated Wastewater Characteristics for the H-Coal Breckinridge Project.

Table 4-38 Sources of Contaminated Stormwater Runoff and Their Anticipated Wastewater Characteristics for the H-Coal Breckinridge Project.

Table 4-39 Major Pollutant Non-Process Wastewater Treatment Plant Profiles (Dry Weather Conditions) for H-Coal Breckinridge Project.

Table 4-40 Projected Characteristics of Liquid Effluents from Non-Process Wastewater Treatment Trains, H-Coal Breckinridge Project.

Table 4-41 H-Coal Combined Process Water Characteristics.

Table 4-42 PACT Bench-Scale Performance.

Table 5-1 Performance of Bench-Scale Ozone Treatment of Synthane Process Water.

Table 5-2 Operating Efficiency for Zimpro Wet Air Oxidation of Hygas Pilot Plant Wastewaters.

Table 5-3 Hygas Run 79 Quench Water Quality Characteristics Through Reverse Osmosis Treatment.

Table 5-4 Comparison of Powdered and Granular Activated Carbon Treatment.

Table 5-5 Average Steady-State Performance Data for Biological Oxidation with the Addition of Powdered Activated Carbon 33% Strength Stripped GFETC Gasifier Wastewater, θ_C = 40 Days.

Table 5-6 Metal Reduction Through Biological and PAC Treatment θ_C = 20 Days, 33% GFETC Stripped Wastewater.

Table 5-7 Priority Pollutant Removal by Chambers Works Plant.

LIST OF TABLES (continued)

Table 6-1	Phenolic Compounds Prevalent in Coal Conversion Quench Liquors.
Table 6-2	Comparative Performance Data for Biological Treatment of Coal Coking and Coal Conversion Effluents.
Table 6-3	Analysis of Ammonia-Stripped H-Coal Combined Sour Water from Processing of Illinois No. 6 Coal.
Table 6-4	Distribution Coefficients at High Dilution for Various Phenolic Compounds Between Water and Selected Solvents.
Table 6-5	Solvent-To-Feed Ratios Employed in Phase I Batch Extraction Experiments.
Table 6-6	Sludge Acclimation Schedule and Viability.
Table 6-7	PHASE II - Treatability Study Design for Batch Experiments.
Table 6-8	Total Phenols Remaining in Aqueous Phase After Solvent Extraction of Stripped H-Coal Sour Water.
Table 6-9	Phenolic Compounds Remaining in Aqueous Phase After Solvent Extraction of Stripped H-Coal Sour Water.
Table 6-10	Total and Individual Phenolic Compounds Remaining in Stripped H-Coal Sour Water Following Batch Solvent Extraction and Shake Flash Biodegradation.

LIST OF FIGURES

Figure 3-1	Coal Conversion Processing Routes.
Figure 3-2	SASOL-SYNTHOL Coal Liquefaction Process.
Figure 3-3	Lurgi MKIV Gasifier.
Figure 3-4	Synthol Fischer-Tropsch Synthesis.
Figure 3-5	Ruhrkohle/Ruhrchemie Design for the Texaco Coal Gasification Process.
Figure 3-6	H-Coal Process Schematic.
Figure 3-7	Lurgi Ruhrgas Flash Pyrolysis Process.
Figure 4-1	Process Modules Generating Solid Waste in the SASOL-SYNTHOL (Hat Creek) Process.
Figure 4-2	Process Modules Generating Solid Waste in the R/R Texaco-Mobil MTG Process.
Figure 4-3	Overall Block Flow Diagram for the H-Coal Breckinridge Project.
Figure 4-4	Process Modules Generating Solid Waste in Lurgi Ruhrgas Pyrolysis and Power Generation Process (Western Canada Low-Sulphur Coal).
Figure 4-5	Material Flow Schematic for the Coal Gasification Section of The SASOL-SYNTHOL Process.
Figure 4-6	Material Flow Schematic for the Synthol and Upgrading Sections of the SASOL-SYNTHOL Process.
Figure 4-7	Sulphur Balance for the SASOL-SYNTHOL Process.
Figure 4-8	Material Flow Schematic for the R/R Texaco Gasification and Methanol Synthesis Processes.
Figure 4-9	Sulphur Balance for R/R Texaco Gasification & Methanol Synthesis Processes.
Figure 4-10	Control Scheme for Sulphur Dioxide Emissions From H-Coal Breckinridge Project.
Figure 4-11	Water Distribution Schematic for a SASOL-SYNTHOL (Hat Creek) Plant.
Figure 4-12	Water Distribution Schematic for an R/R Texaco-Mobil MTG Plant.

LIST OF FIGURES (continued)

Figure 4-13	Overall Water Flow Schematic for H-Coal Breckinridge Project.
Figure 4-14	Water Balance for the H-Coal Breckinridge Project.
Figure 4-15	Schematic of Treatment Trains for Non-Process and Process Wastewaters Generated by the H-Coal Breckinridge Project.
Figure 5-1	Gravity Separators for Petroleum Wastewater.
Figure 5-2	Dissolved Air Flotation Process (Recycle Flow Pressurization).
Figure 5-3	Conventional Filter Configurations.
Figure 5-4	Refluxed Sour Water Stripper.
Figure 5-5	Flow Schematic of the USS Phosam-W Process.
Figure 5-6	Flow Schematic for the Chevron WWT Process.
Figure 5-7	Flow Schematic for the Phenolsolvan Process.
Figure 5-8	Chem-Pro Process.
Figure 5-9	Wet Air Oxidation Process.
Figure 5-10	Reverse Osmosis Membrane Configurations.
Figure 5-11	Vapour Recompression (Mechanical) Evaporation.
Figure 6-1	Pattern of Phenolic Compound Production in Coal Gasification Processing.
Figure 6-2	Experimental Procedure for the Preliminary Treatability Study - PHASE I.
Figure 6-3	Experimental Procedure for the Preliminary Treatability Study - PHASE II.
Figure 6-4	Total Phenols Extraction Efficiency of Various Solvents and Solvent Mixtures.
Figure 6-5	Phenol Species Extraction Efficiency of 2-Octanone on Stripped H-Coal Sour Water.
Figure 6-6	Phenol Species Extraction Efficiency of MIBK on Stripped H-Coal Sour Water.

LIST OF FIGURES (continued)

Figure 6-7 Shake Flask Biodegradation of 2-Octanone-Extracted H-Coal Stripped Sour Water - PHASE I.

Figure 6-8 Shake Flask Biodegradation of MIBK-Extracted Stripped H-Coal Sour Water - PHASE I.

Figure 6-9 Shake Flask Biodegradation of MIBK-Extracted H-Coal Stripped Sour Water - PHASE II.

Figure 6-10 Shake Flask Biodegradation of 2-Octanone-Extracted H-Coal Stripped Sour Water - PHASE II.

1. EXECUTIVE SUMMARY

The diminishing supply of conventional domestic oil reserves and the high cost of imported crude has led to an increase in research activity aimed at the development of alternate energy supplies. The enormous North American low-grade coal resource could support the production of synthetic fuels and chemical feedstocks through the application of coal liquefaction and gasification techniques. Various Canadian research and development programs along with some specific studies for commercial plants have been initiated, many under the auspices of the National Energy Program and provincial government initiatives. The Environmental Protection Service of Environment Canada, in cooperation with Energy, Mines and Resources and the Department of Supply and Services, has therefore, undertaken to establish an environmental assessment of coal conversion processes which may be introduced in Canada within the next decade.

A detailed review was conducted on coal liquefaction and gasification projects worldwide including information on individual proprietors, process technologies used, their present status, and available environmental data. Based on discussions with Canadian government agencies and potential proprietors, the study further focussed on direct and indirect liquefaction technologies close to commercialization in Canada, namely: SASOL-Synthol (SASOL II) indirect liquefaction, Ruhrkohle/Ruhrchemie Texaco Gasification - Methanol Synthesis - Mobil MTG Gasoline Synthesis, H-Coal direct liquefaction, and Lurgi Ruhrgas Pyrolysis/Power Generation.

A critical assessment was made of air, water, and solid wastes emanating from commercial-scale plants utilizing the above selected technologies. Where possible, the assessment included unique environmental factors arising from the location of such plants in specific Canadian settings. From this assessment a summary of significant and potentially significant wastestreams from these technologies was compiled.

Particular emphasis was placed upon wastewater discharges. Available information on applicable coal conversion wastewater treatment/reuse technologies was therefore included in the report. The review indicated the need to assess minimum solvent extraction pretreatment followed by biological treatment to remove bulk organic and toxic contaminant load.

A bench-scale investigation of minimum extraction pretreatment of H-Coal process wastewater with MIBK and 2-octanone solvents followed by bio-oxidation showed that such an approach is feasible in terms of organic contaminant removal efficiency and potentially reduced costs relative to by-product phenol recovery schemes.

1. RÉSUMÉ

La diminution de nos réserves naturelles de pétrole et le prix élevé du pétrole brut importé ont amené une intensification des activités de recherche visant à exploiter d'autres sources d'énergie. L'énorme quantité de charbon de qualité inférieure que l'on trouve en Amérique du Nord pourrait aider à la production de combustibles synthétiques et de matières chimiques de base grâce à l'application des techniques de liquéfaction et de gazéification du charbon. Divers programmes canadiens de recherche et de développement ainsi que certaines études particulières pour les entreprises commerciales ont été mis en oeuvre, en grande partie dans le cadre du Programme énergétique national et de projets provinciaux. Le Service de la protection de l'environnement d'Environnement Canada, en coopération avec le ministère de l'Energie, des Mines et des Ressources et celui des Approvisionnements et Services, a donc décidé de faire l'évaluation environnementale des procédés de conversion du charbon qui pourront être mis en place au Canada au cours de la prochaine décennie.

Il a effectué une étude détaillée des entreprises de liquéfaction et de gazéification du charbon dans le monde et a recueilli des renseignements sur leurs propriétaires, les procédés utilisés et leur degré d'avancement ainsi que sur les données environnementales disponibles. A la suite de discussions avec des organismes gouvernementaux et des propriétaires éventuels canadiens, l'étude a été poussée plus loin et a porté sur les techniques de liquéfaction directe et indirecte sur le point d'être commercialisées au Canada, notamment sur la méthode de liquéfaction indirecte SASOL-Synthol (SASOL II), sur la technique de gazéification et de synthèse du méthanol Ruhrkohle/Ruhrchemie Texaco, sur la méthode de synthèse de l'essence Mobil MTG, sur le procédé de liquéfaction directe H-Coal ainsi que sur la technique Lurgi Ruhrgas de production d'énergie par pyrolyse.

On a fait une évaluation critique des émissions, des effluents et des déchets solides produits par les installations commerciales utilisant les techniques mentionnées plus haut. Autant que possible, on a étudié les facteurs environnementaux particuliers aux endroits où pourraient se trouver ces installations au Canada. Grâce à cette évaluation, on a dressé une liste des polluants résultant de l'utilisation de ces méthodes et qui ont des incidences importantes ou pourraient en avoir.

On s'est arrêté en particulier sur le rejet des effluents et on a donc inclus dans le rapport les renseignements qu'on possédait sur les méthodes de traitement et de réutilisation applicables aux effluents résultant des procédés de conversion du charbon. L'étude a démontré la nécessité d'un traitement préliminaire minimum avec extraction par solvant suivi d'un traitement biologique pour éliminer la plus grande partie des contaminants organiques et toxiques.

Une recherche en laboratoire sur le traitement préliminaire minimum par extraction avec la méthylisobutylcétone et la méthylhexylcétone des effluents résultant de l'application du procédé H-Coal, suivi d'une bio-oxydation, a démontré que cette méthode permet l'élimination efficace des contaminants organiques et peut éventuellement réduire les coûts de récupération du phénol présent comme sous-produit.

2. INTRODUCTION

In response to the priority given to development of coal conversion technology under the National Energy Program, the Environmental Protection Service (EPS), through the Wastewater Technology Centre, has initiated a range of applied research programs to provide the necessary information to assess the potential environmental implications of coal conversion technologies. As a first step, an evaluation has been undertaken to identify future potential multi-media environmental problems resulting from the implementation of coal conversion projects in Canada. Dearborn Environmental Consulting Services has been retained to conduct this study.

Although this study serves to identify potential problems from air, water and solid wastes discharges, particular emphasis is placed upon wastewater discharges and currently available treatment methods. Wastewaters containing process condensates from coal conversion processes are reported to contain a wide range of toxic and inhibitory compounds including phenols, cyanides, ammonia, polyaromatic hydrocarbons, heterocyclic nitrogenous compounds and trace organic priority pollutants.

A detailed review has been made of coal gasification and liquefaction projects worldwide including information on individual proprietors, process technologies used, their present status, and available environmental data. On the basis of this review, it was decided that emphasis should be placed on those technologies that are close to commercialization in Canada. The possible scenarios applicable to individual regions in Canada (British Columbia, Alberta, Saskatchewan, Ontario and the Maritimes) have been reviewed with respect to the actual potential for commercial coal conversion process installations as well as their environmental implications.

Following discussions with government agencies such as CANMET and EPS, and individual potential proprietors, it was concluded that this study should focus on coal liquefaction rather than coal gasification projects. In their recommendations to the House of Commons in 1981, the Parliamentary Special Committee on Alternate Energy and Oil Substitution stated that while the coal liquefaction option should not be adopted for the long-term, a limited number of plants could be accepted in the shorter term "with stringent environmental safeguards"[1].

The detailed review of air, liquid, and solid wastes discharges has, therefore, been based upon coal liquefaction studies which could lead to proposals to build commercial facilities in Canada by the next decade. These are:

Hat Creek Liquefaction Project

B.C. Hydro initiated a prefeasibility study for a SASOL II-type liquefaction facility at the south Hat Creek coal site in British Columbia.

Scotia Coal Synfuels Project

A consortium including Cape Breton Development Corp., Nova Scotia Resources Ltd., Petro-Canada Exploration Inc., Gulf Canada Products Co., and Noval Technologies Inc., initiated a study to evaluate the feasibility of siting a coal liquefaction plant on Cape Breton Island. The Federal and Nova Scotia Governments pledged $1 million from the Atlantic Region Oil Substitution Fund towards this work.

Integrated Coal Pyrolysis/Power Generation

Fording Coal Ltd. initiated a feasibility study for Alberta Coal flash pyrolysis and power generation from produced

char. CANMET has explored similar processing for suitable Eastern coals.

These studies have included the selection and evaluation of optimal commercial or near-commercial coal conversion technologies. The sensitivity of process operation and product composition to the feed coal petrography is an important consideration in the environmental analysis of the selected technologies. To date, it is believed that no testing of Canadian coals in coal conversion processes at a scale larger than micro-autoclave or bench-scale has been attempted. In some circumstances, however, foreign coals bearing reasonable similarities to Canadian coals in terms of ash, sulphur, oxygen and hydrogen to carbon ratio have been tested at pilot or commercial units of the selected process. Environmental data generated during runs of these coals have been procured where available.

The review of the literature on available coal conversion wastewater treatment processes indicated that biological treatment is important in the formulation of control strategies for commercial plants. Solvent extraction and ammonia stripping for by-product phenols and ammonia recovery, respectively, is practised prior to biological treatment at the South African SASOL operations and is included in the design of plants currently proposed or under construction in North America. The pretreatment processes remove the need for significant dilution of high-strength coal conversion process wastewaters to reduce bio-inhibitory compounds to acceptable levels. Bench-scale biodegradation studies, utilizing severe extraction pretreatment to reduce phenol levels by 90 percent or greater, have shown the beneficial effects of extraction on overall wastewater biodegradability, toxic contaminant removal and nitrification. Little work, however, has been done to investigate the impact of reduced extraction severity on subsequent biological treatment. Since maximum ammonia levels are well-established for biological processes, a

lab-scale screening study was undertaken to investigate minimum solvent extraction pretreatment coupled with bio-oxidation of the remaining unextracted organic load. Of the coal conversion processes evaluated, only one, the H-Coal process, was in operation at a relatively large pilot scale in North America. Wastewater from this process was therefore used in this work.

3. REVIEW OF PROCESS TECHNOLOGY

3.1. Coal Conversion Process Routes

There are four basic process routes to produce a liquid or gaseous fuel from coal:

1) Gasification
2) Hydrogasification
3) Indirect Liquefaction
4) Direct Liquefaction

Gasification involves the production of carbon monoxide and hydrogen (synthesis gas) from the carbon-steam reaction. Heat for the endothermic reaction is supplied by the combustion of carbon with either air or pure oxygen to produce a low calorific value or medium calorific value gas, respectively. The synthesis gas product can be upgraded to high calorific value synthetic natural gas by shifting the carbon monoxide-hydrogen ratio and subsequently combining the components in a catalytic reaction to form water and synthetic natural gas (SNG).

Hydrogasification involves direct reaction of carbon and hydrogen at high pressures to form SNG.

In the indirect liquefaction route, synthesis gas can be processed in two different ways to yield liquid products. The first relies on catalytic Fischer-Tropsch synthesis to yield a spectrum of hydrocarbon and oxygenated organic products similar to a partially-processed crude oil. In the second method, methanol is produced from synthesis gas by one of several available commercial processes.

Methanol can be upgraded further into high-octane gasoline by the recently commercialized Mobil MTG catalytic process. Mobil is

also developing a methanol to diesel fuel process for near-future commercialization.

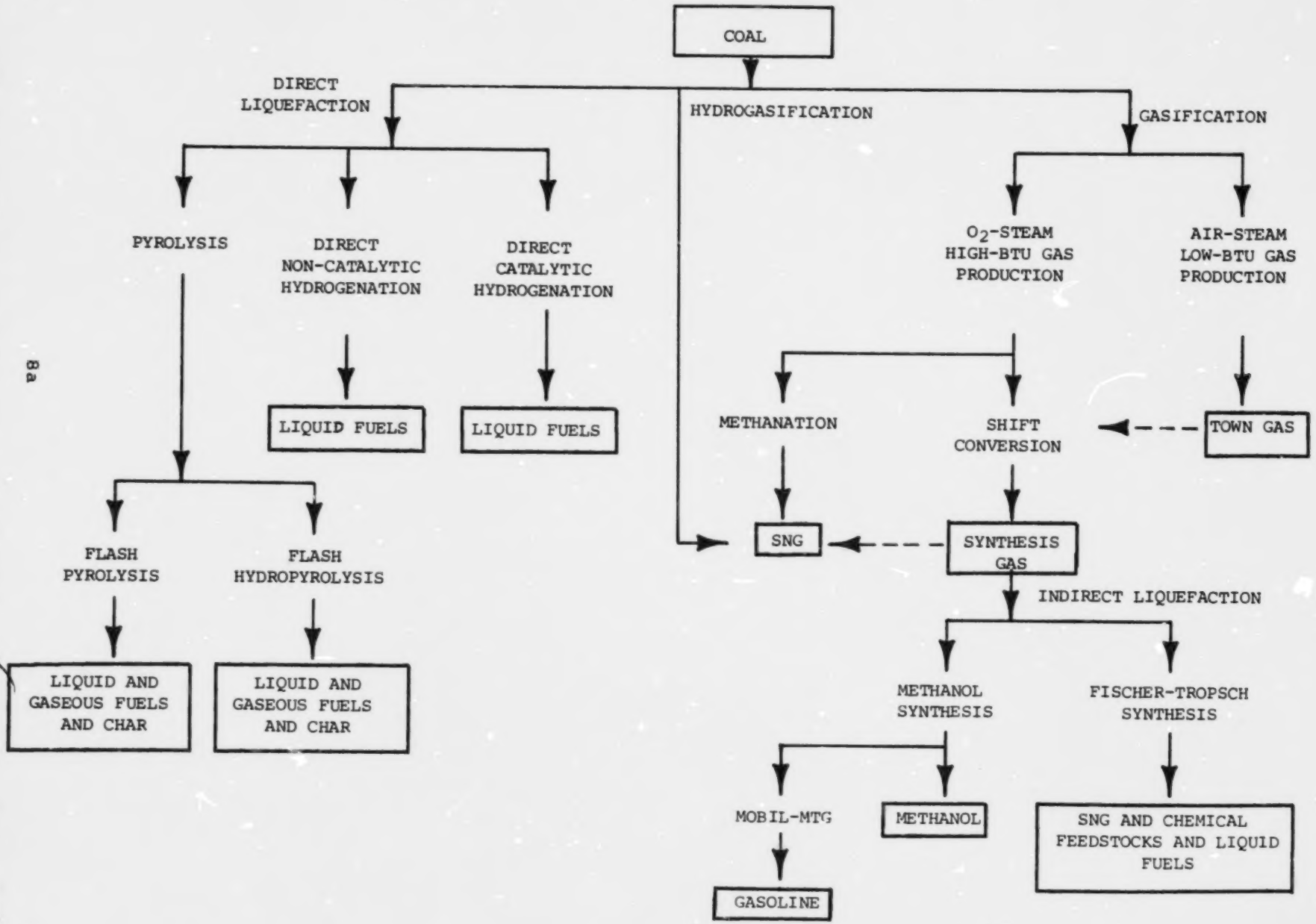
Direct liquefaction refers to either the controlled hydrogenation of the coal to yield lower molecular weight hydrogen-rich compounds or the release of volatile compounds in the coal by flash pyrolysis with or without external hydrogen addition to improve yields. The flash pyrolysis method yields liquid and gaseous fuels and a char product generally having good combustible qualities.

The controlled hydrogenation (direct hydroliquefaction) method involves slurrying coal with a hydrogen-rich recycle solvent in the presence of hydrogen, allowing the solvent to de-polymerize the coal and facilitate hydrogenation in either an uncatalyzed, high-pressure or (reduced residence time) catalyzed reaction. Synthetic crude oil requiring refinery upgrading is produced from these processes. Following ash separation, the heavy residual fraction is generally gasified to yield make-up hydrogen.

Figure 3-1 presents an overall schematic representation of coal conversion processing routes.

FIGURE 3-1

COAL CONVERSION PROCESSING ROUTES



3.2. History and Present Status of Coal Conversion Technology

Commercialized gasification and liquefaction of coal is not a recent development. Coal itself became a commercial commodity early in the thirteenth century. In 1621, it was used to smelt iron which initiated interest in coking technology. The value of the tar and gas evolved in this operation was not recognized until 1770 when the first by-product coke oven appeared, effectively the first coal gasifier. The onset of the industrial revolution created many new uses for coke by-product chemicals and gaseous fuels which led to the construction of the first low-BTU gasifier by Siemens AG in 1832. By 1875, commercial low-BTU producers and a newly-developed steam-coal gasifier were offering an alternate fuel source on a large-scale and, in concentrated coal burning regions, a reprieve from severe atmospheric pollution. Until being supplanted by natural gas in the early 1920's, coal-based water gas or town gas producers were a common feature in North America and Europe.

The Bergius concept of direct hydrogenation coal liquefaction was demonstrated in 1921 and experimental work on synthesis of hydrocarbons from water gas - Fischer-Tropsch synthesis - was published in 1923. The emergence of petroleum fuels, however, delayed their full-scale application until World War II where the production of gasoline and chemical feedstocks from coal became of great strategic importance to the German military[2].

While research and development in Germany and England during the period 1930 to the mid-60's produced several new gasification processes, the one significant application remained the SASOL I indirect liquefaction operation in South Africa (on-stream in 1955). The period 1963 to 1977, however, saw U.S. industry and government coal-related energy research increase 11 and 35-fold, respectively. This effort received an additional impetus from the energy crisis spurred by the OPEC oil embargo of 1973 and

also by public resistance to accelerated nuclear energy development. The research spawned a multitude of new approaches to coal conversion with the goal of increased efficiency and control over the product slate. Several of these "second generation" technologies have progressed to the commercialization stage.

Government involvement in coal conversion technology in the U.S. was significantly increased by the Carter administration which allocated large sums to a synfuels program designated as strategic and established the Synthetic Fuels Corporation (SFC). The program has suffered cutbacks under the current Reagan administration due to a change in stability of the OPEC cartel. However, the SFC has remained relatively intact and has, at present, sufficient funds to provide loan and price guarantees for several multi-billion dollar projects.

Meanwhile, Germany and Japan have initiated vigorous development programs mainly with the aim of demonstrating and exporting technology. As well, many nations possessing significant coal reserves such as the U.S.S.R., Canada, China, Brazil and Australia are currently evaluating imported technologies which suit their particular coals and end-product requirements. U.S. coal conversion output by 1990 is presently estimated at 150,000 to 250,000 bbl/d oil equivalent while significant output from countries other than South Africa and Germany is not projected until the year 2,000 at least[3].

In Appendix A, summary tables are presented listing coal conversion technologies, both demonstrated and in the developmental stage, as well as a worldwide listing of coal conversion projects.

Tables A-1 and A-2 present a breakdown of current coal gasification and liquefaction technology. Second generation processes are defined as those expected to be proven at the commercial-scale by 1990. Third generation processes are those in

development either at the Process Development Unit (PDU) or pilot-scale stage and which will have a future impact due to increased conversion and operating efficiency. The technologies listed in Table A-1 are further subdivided by the mode of contacting coal and the gasifying medium as well as by air or pure oxygen requirement where applicable.

Tables A-3, A-4, A-5 and A-6 present a listing of coal gasification and liquefaction projects worldwide as of January 1983. The project listing was determined from a detailed literature review and, where possible, personal communication with process licensors and developers. The order of listing for projects operational or under construction and, where possible, those expected on-stream by 1990, is made by the year or expected date of plant start-up. The terms gasification and liquefaction refer to the final product of major significance from the plant. Projects where combined cycle power generation and some liquid or gaseous by-products are derived are listed as gasification projects.

Finally, listed projects in the engineering or feasibility study stage are those expected to have the greatest potential to be on-stream or under construction by 1990 as reflected in their status with the SFC selection program and the degree of private funding involved.

3.3. Description of Selected Processes

There are three main proposals which may lead to coal conversion projects in Canada by the next decade. Each of these is a coal liquefaction project. However, the three main routes to liquid fuels from coal are represented: direct liquefaction, indirect liquefaction, and pyrolysis.

The four process technologies associated with these proposals are proven or at the threshold of commercialization and are listed below:

1) Hat Creek - SASOL II-type Indirect Liquefaction
LURGI MKIV DRY-ASH/SYNTHOL FISCHER-TROPSCH

2) Scotiacoal Synfuels - Indirect liquefaction
RUHRKOHLE/RUHRCHEMIE TEXACO with
METHANOL SYNTHESIS/MOBIL MTG or
Direct Liquefaction
H-COAL

3) Pyrolysis liquids/power generation - Flash Pyrolysis
LURGI RUHRGAS

3.3.1 SASOL - SYNTHOL (SASOL II) Process

Sasol II-type indirect coal liquefaction represents the maturation of process technology implemented in SASOL in 1955 which is still operational today. Lurgi gasification was first demonstrated in 1930 and commercialized in 1940. At SASOL II, the Lurgi Mark IV oxygen-blown gasifier is only a slight modification of the original oxygen-blown gasifier used in SASOL I.

Fischer-Tropsch synthesis was developed during World War II in Germany. SASOL I employs two types of processes - fluidized-bed Synthol and fixed-bed Arge Fischer-Tropsch synthesis. SASOL II has a modified Synthol procedure developed at Sasol involving mainly an improved catalyst.

Lurgi Kohle and Mineraloeltechnik GmbH has also developed several subsidiary processes for use with the Lurgi gasification process. These include Rectisol acid gas treatment, Phenolsolvan phenol recovery, a catalytic water gas shift conversion process, a tar/oil/gas liquor separation process, a hot gas recycle methanation process and, in conjunction with Chemie Linz AG., an anhydrous ammonia recovery process. Most of these processes are specified for Lurgi SNG plants being proposed in the U.S. at present.

The Sasol coal liquefaction scheme is presented diagramatically in Figure 3-2. The first step in the process involves coal sizing. Crushed coal is separated into a minus 3mm fraction and a 3 - 50mm gasifier feed fraction. The minus 3mm coal fines are combusted for plant steam and power requirements.

The Lurgi Mark IV gasifiers are 4m in diameter and operate at 25 bar pressure. A schematic of the gasifier and raw gas cooling train is shown in Figure 3-3. Coal, steam and oxygen are fed into the reactor in the weight ratio 1.00 : 1.25 : 0.36. Coal is introduced intermittently through a lockhopper system at the top while steam and oxygen are injected together continuously at the bottom. As the coal descends counter-currently through hot ascending gases, it passes successively through a drying zone, a devolatization zone at 600°C to 750°C, a char-gasification zone up to 1,200°C, and an unreacted char-combustion zone at the bottom which supplies the heat for the previous endothermic reactions.

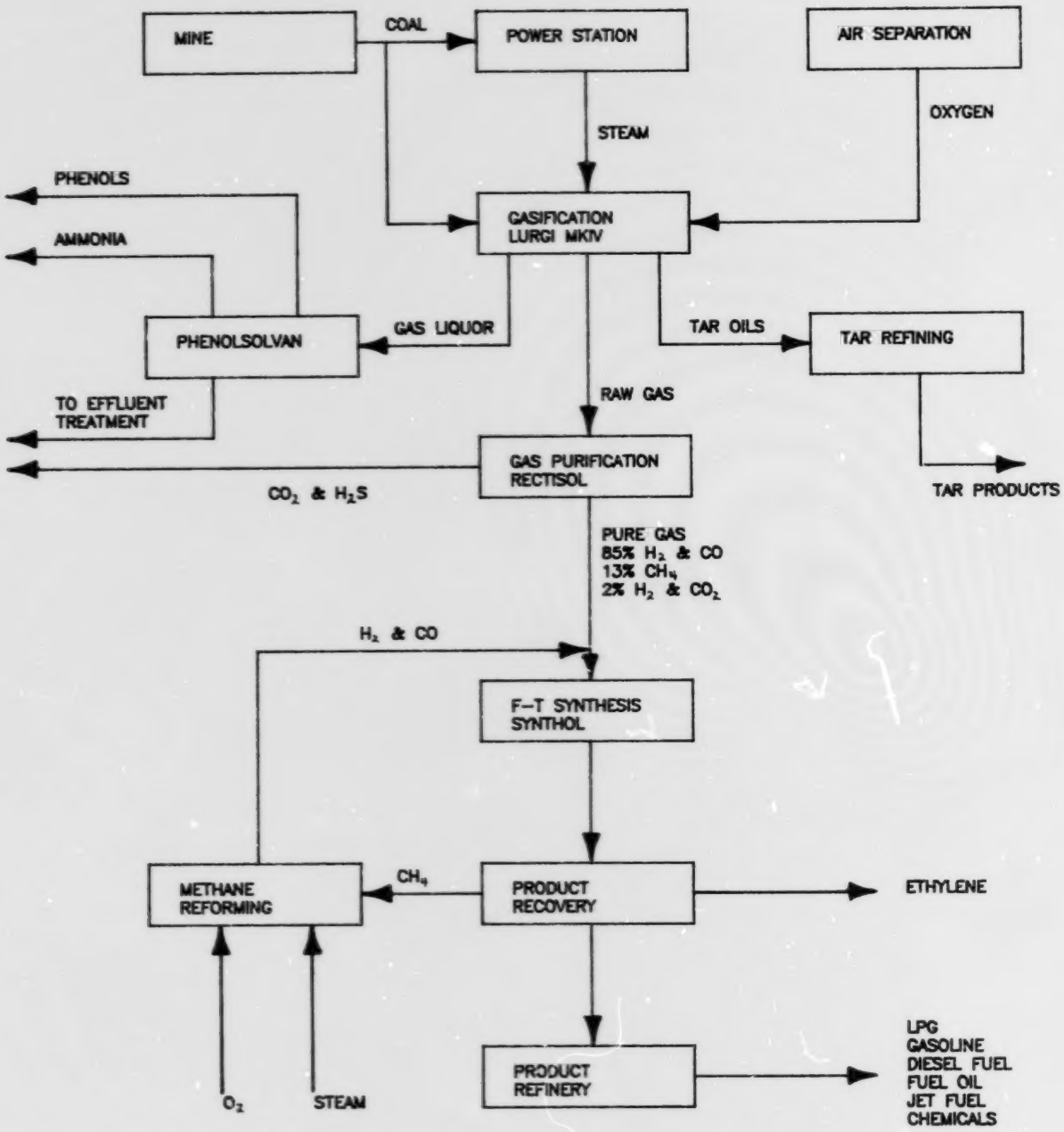


FIGURE 3-2 SASOL-SYNTHOL COAL LIQUEFACTION PROCESS

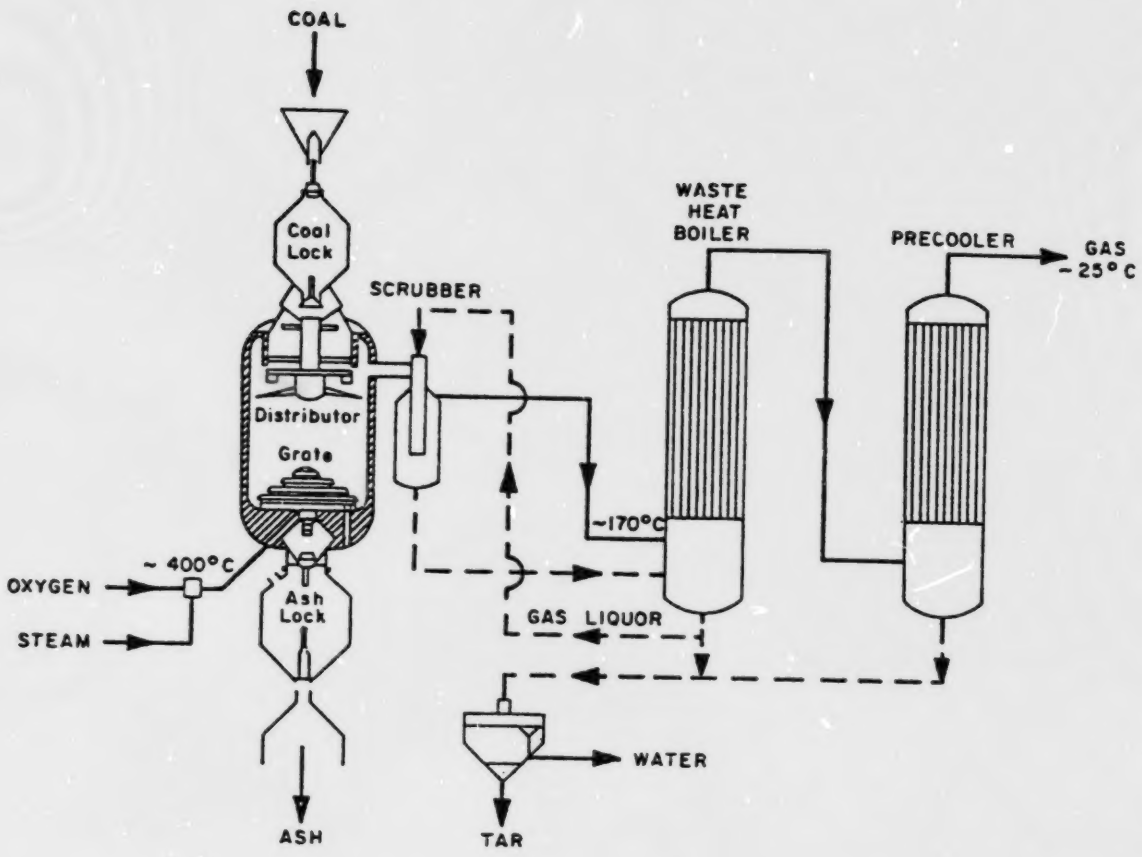


FIGURE 3-3 LURGI MkIV GASIFIER

The raw gas leaves the gasifier at 400 to 600°C. It is composed primarily of H_2, CO, CO_2, CH_4, NH_3, H_2S and unreacted steam. In addition, tars, oils, phenols, fatty acids, and entrained particles, plus reduced sulphur and nitrogen compounds such as COS, mercaptans, and HCN are produced. The raw gas is quenched in a recycled water scrubber to 160°C to 180°C for removal of tar, oil, phenol and other high molecular weight organics as well as particulate reduction. The gas is then cooled to 25°C in a precooler prior to clean-up in the Rectisol process to a total sulphur concentration of less than 0.05 ppm.

The repressurized and reheated cleaned gas is then fed with recycle gases at 23 bar and 160°C to the Synthol reactor shown schematically in Figure 3-4. Feed gases are mixed with fluidized iron-based catalyst in the reactor standpipe at 335°C which promotes synthesis of hydrocarbons, alcohols, aldehydes, ketones and organic acids in an overall exothermic reaction. Catalyst and product gas are separated in cyclones and heat is removed by cooling coils for high-pressure steam generation. The product gases are then successively cooled and scrubbed to yield heavy or decant oil, light oil, aqueous chemicals and a gaseous fraction which is usually recycled. The final product is then analogous to a partially processed syncrude.

3.3.2. Ruhrkohle/Ruhrchemie Texaco Gasification

The Ruhrkohle/Ruhrchemie version of the Texaco Gasification process, hereafter referred to as the R/R Texaco process, is based on the U.S. Texaco Oil Partial Oxidation research initiated in 1948. Work on the German version of the process has focussed on the coal preparation and heat recovery aspects while leaving the gasifier basically unchanged. Ruhrkohle AG, Ruhrchemie AG and Texaco Inc. are now under a joint development agreement for the process

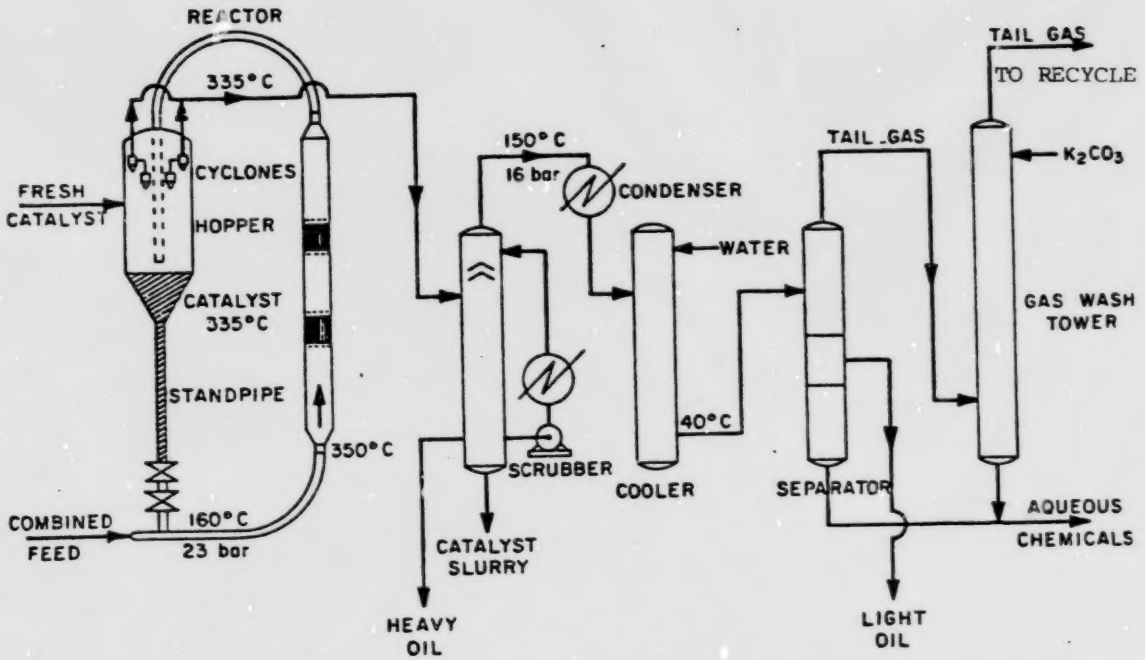


FIGURE 3-4 SYNTHOL FISCHER-TROPSCH SYNTHESIS

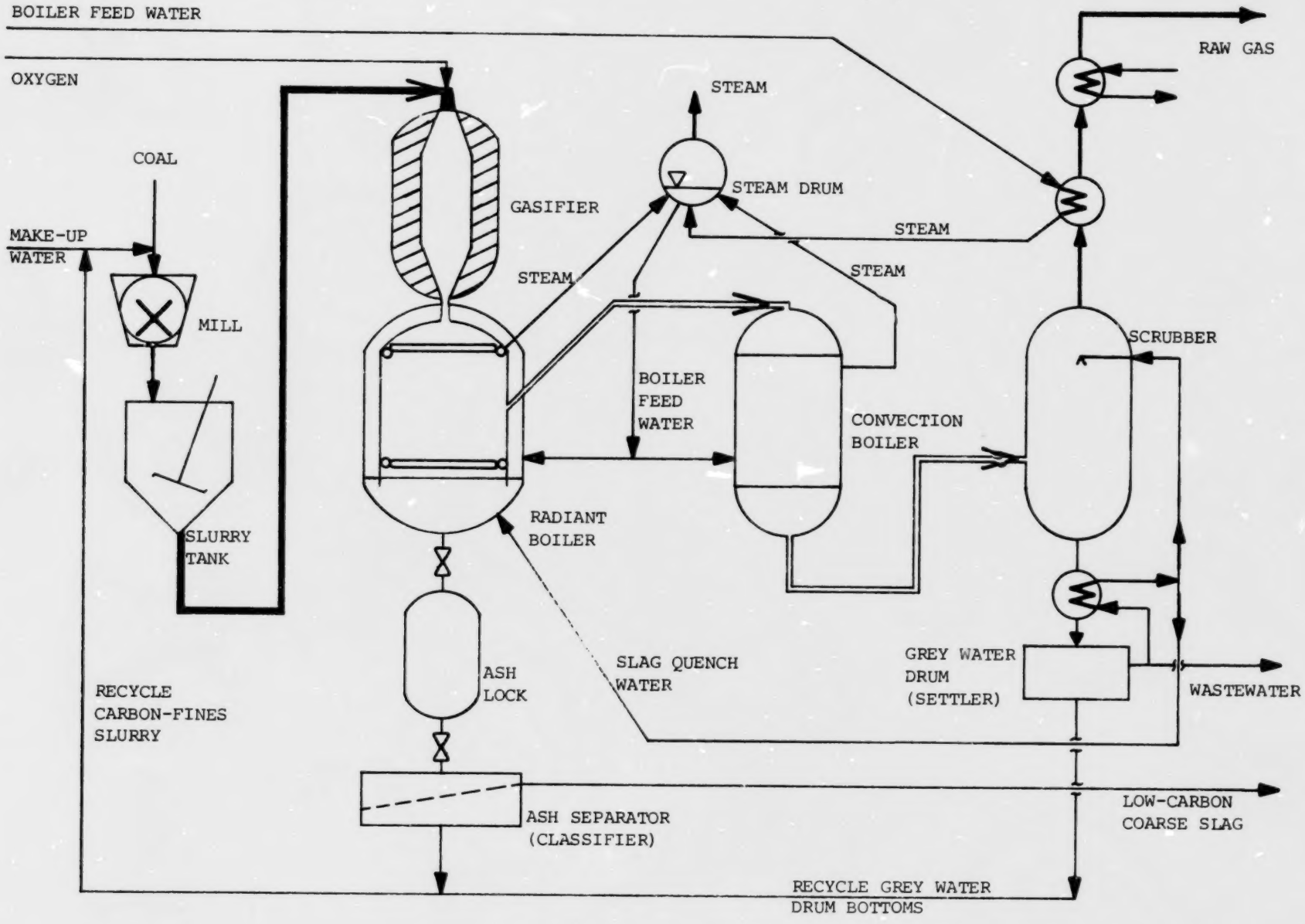
which has been demonstrated at pilot scale (180 tonne/d) since 1978 in Oberhausen, West Germany. The U.S. version has been operated at the 45 tonne/d, 90 tonne/d and 180 tonne/d scale at Montebello, California, Morgantown, West Virginia, and Muscle Shoals, Alabama, respectively. The gasifier can process many coals as well as coke, char, and vacuum resid bottoms from petroleum and tar sands syncrude refineries. It was evaluated for the Alsands project in this latter capacity.

A schematic of the R/R Texaco process is shown in Figure 3-5. Coal is wet ground to minus 200 um with additives to form a pumpable, high-solids slurry made up of coal process recycle water. The solids content of up to 70 percent and viscosity are controlled on-line along with flow metering. The mixture is brought up to the reactor pressure of 40 bar in a stirred storage tank, and injected with pure oxygen into the refractory-lined reactor through a special burner. Pure gaseous oxygen is injected at a weight ratio of about 1:1 coal to oxygen to provide combustion heat for the endothermic coal-steam reaction. Reaction temperature reaches a maximum of about 1,500°C. Reaction products are primarily H_2, CO, CO_2, H_2S, COS and small quantities of NH_3 and CH_4 plus slagged ash. Apparently, no long chain or aromatic hydrocarbons have been formed in any of the Texaco pilot-plant runs.

The hot, molten slag-containing raw gas is discharged to a radiant cooler where the products are cooled to below the ash sintering temperature to allow coarse solids-gas separation. The raw gas containing some fine ash is fed to a convective cooler. High pressure steam is generated in both preliminary cooling stages.

Solidified slag is removed from the pressurized radiant cooler via a lock hopper system and transported in a water

FIGURE 3-5 RUHRKOHLE/RUHRCHEMIE DESIGN FOR THE TEXACO COAL GASIFICATION PROCESS



slurry. Unconverted carbon can be recycled subsequent to a slag classification step. Following high-level waste heat recovery in the convection boiler, the raw product gas is scrubbed for particulate removal then cooled further in two successive low-level waste heat recovery boilers. Scrubber liquor blowdown and slag quench blowdown can be recycled to the coal slurry preparation stage.

3.3.3. H-Coal Process

The H-Coal process is an application of the ebullated-bed reactor proven at commercial-scale by Hydrocarbon Research Inc. (HRI) in the H-Oil process for upgrading heavy oil. Development of the H-Coal process, initiated in 1964, has progressed through the micro-autoclave, bench-scale (11 kg/d), process development unit (PDU) scale (3 tonne/d) and has been tested at the pilot-scale in Catlettsburg, Kentucky since early 1980.

The pilot-plant can operate in two modes - the syncrude mode at 180 tonne/d, and the fuel-oil mode at 545 tonne/d. There are no plans at present, however, to operate in the fuel oil mode despite having its feasibility verified on the PDU unit. Operational adjustments and data gathered from the processing of Illinois No. 6, Kentucky No. 9 and Wyodak coal has provided the design basis for $5.2 billion facility producing 4,000 m^3/d (25,000 bbl/d) syncrude from 8,200 tonne/d coal. At present, the proposed plant has been reduced in size to 5,000 bbl/d and will be located in Breckinridge County, Kentucky.

The overall process schematic is shown in Figure 3-6. Coal is ground to minus 850 um particle size, dried and slurried with a process-derived recycle oil at about 50 percent solids by weight. Some hydrogen is added before feed pre-heat and pressurization while the remaining hydrogen

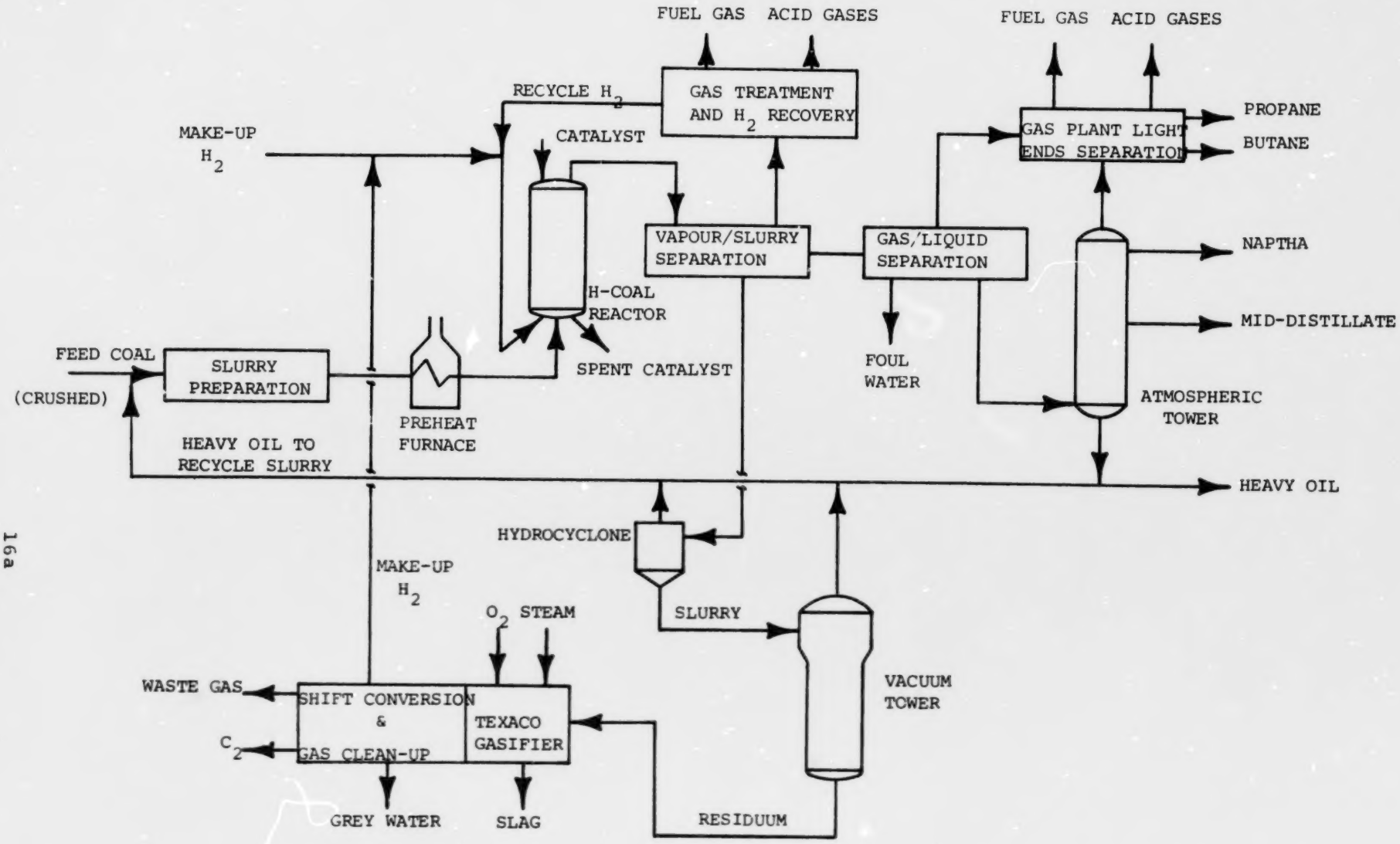


FIGURE 3-6

H-COAL PROCESS SCHEMATIC

requirement is pressurized and pre-heated separately. These streams are fed into the reactor at 600 - 650°C and 15,500 - 17,200 kPa pressure. Reaction temperature in the well-mixed ebullated-bed reactor is 800 - 850°C and maintained by the exothermic hydrogenation reaction. Internal mixing is achieved through internal recycle of liquid streams and up-flow of gaseous streams. Catalyst is continuously exchanged with the reactor at a rate of about 0.50 - 0.60 kg/tonne of feed coal through a lockhopper system.

Reaction products in the gaseous phase leave the reactor with a small amount of particulates and pass through initial cooling and separation in heat exchangers. The products are then separated in heavy, light and gaseous fractions by water injection followed by flash pressure reduction in two successive steps to 750 and 50 psig. Hydrogen is recovered from the initial flash separation and recycled. The heavy fraction is sent to a vacuum tower following initial ash solids removal in a hydrocyclone. The vacuum tower bottoms can then be gasified to produce make-up hydrogen. The feasibility of resid gasification has been proven in the Texaco Gasification process at the Montebello pilot-plant.

The recycle oil is derived from the overhead product from the initial flash separation. The main products of the process (syncrude mode) are fuel oil, light oil, naptha and a relatively small amount of fuelgas. Sulphur and nitrogen compounds are removed in the aqueous streams as primarily H_2S, COS, NH_3, NO_3, and SCN.

3.3.4. Lurgi Ruhrgas Flash Pyrolysis Process

The Lurgi Ruhrgas process was first demonstrated at the 9 tonne/d pilot-scale in 1949. Economic conditions delayed further work until 1960 with the process being developed to the commercial-scale by 1963 at a 2,900 tonne/d

char-producing plant in Lukavac, Yugoslavia. Two smaller plants have been built in Germany and Great Britain again with char as the principle saleable product. Renewed interest in liquid products has prompted the construction of a 22-tonne/d pilot unit in Essen, West Germany. The unit was operational in 1980 and is used for process improvement and coal testing purposes. A test run commissioned by AOSTRA on Alberta tar sands was concluded in December 1980 and may result in the construction of a demonstration unit for this purpose.

The Lurgi Ruhrgas process schematic is shown in Figure 3-7. Coal is crushed to 4 to 5mm particle size and contacted with hot recirculated pyrolysis char at a char to coal ratio of 8:1 in a low-pressure (1.0 - 1.3 bar) mechanical screw mixer. Contact with the recycle char at 700°C results in rapid heating of the mixture to about 600°C during a total residence time of approximately 1.8 seconds. Most of the pyrolysis vapours are formed in the mixer and then escape through cyclones for particulate removal followed immediately by quenching in two successive water scrubbers. The underflow from the second scrubber contains the heavy oil fraction and the overhead product is cooled further to yield a middle oil and raw fuel gas. The aqueous stream contains H_2S, COS, NH_3, SCN and polar aromatic hydrocarbons.

Char is discharged from the mixer into a surge bin then conveyed pneumatically by hot combustion gases to the mixer feed hopper. Air is introduced into the riser to promote controlled char combustion for process heat loss make-up. A portion of the char is removed to maintain the proper coal-char feed ratio and transported to further handling systems. The export char generally has a heating value slightly higher than the parent coal despite a doubling in ash content. This is accounted for mainly by the moisture and oxygen reduction of the feed.

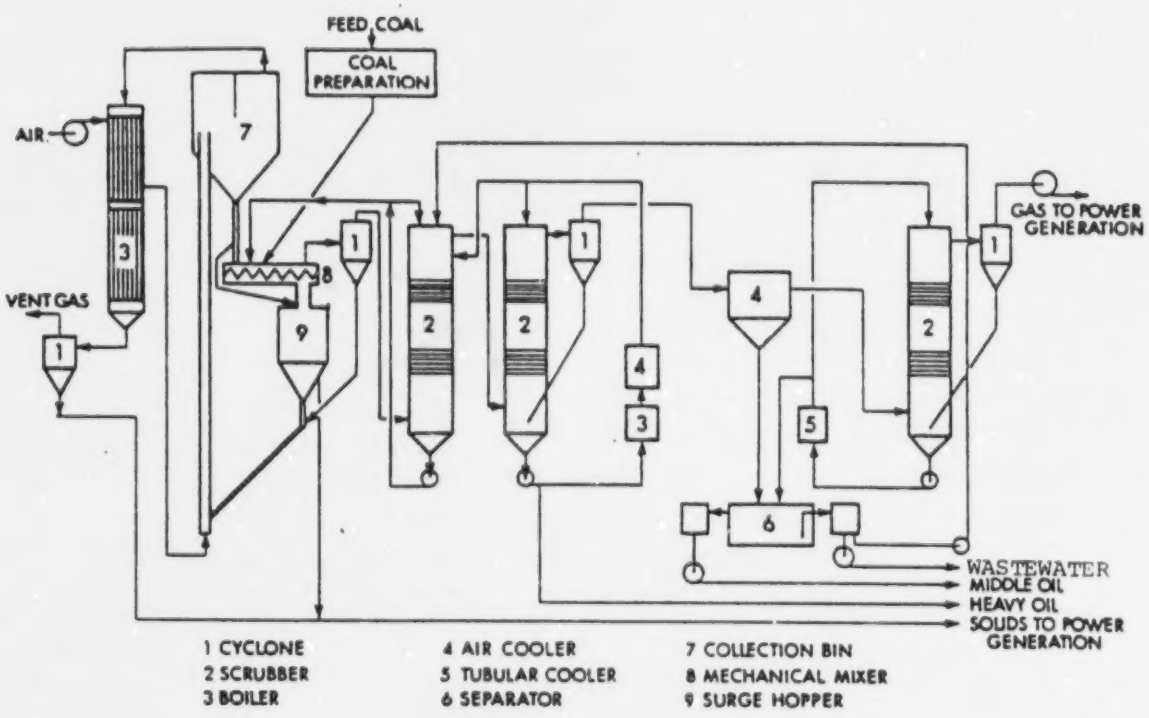


FIGURE 3-7 LURGI RUHRGAS FLASH PYROLYSIS PROCESS

3.4. Comparison of Canadian Coals With Selected Process Coal Feedstocks

The properties of a coal being considered for coal conversion can be the most important factor in the ultimate selection of a process. The high clay and oxygen content of Hat Creek coal, for example, has precluded the use of slagging or direct hydrogenation processes for liquefaction[5]. In addition, only those Canadian coals containing approximately greater than 35 percent volatile matter, such as Cape Breton Sydney coals and Highvale coal, would be considered for flash pyrolysis liquefaction since liquid yield is a direct function of volatile matter content.

As outlined previously in Section 3, process selection for environmental evaluation in this study is related to three main prospects for coal conversion commercial plants in Canada in the next decade. The literature review has centered on the processing of coals that are similar to Canadian coals. Criteria for coal selection and the comparative coal analyses are presented below:

a) Hat Creek Project

From a review of many different U.S. coals which have been tested at SASOL I and the Lurgi facility at Westfield, Scotland, it has been determined that Hat Creek coal compares favourably with the South African sub-bituminous coal feedstock to the SASOL plants. Therefore, operational data from SASOL I and II is emphasized in the environmental analysis of this technology for Canada. It should be noted, however, that there appears to be considerable differences in trace element levels between the coals. Table 3-1 shows a comparative analysis of these coals from available information.

TABLE 3-1 COMPARATIVE ANALYSIS OF HAT CREEK AND SOUTH AFRICAN (SASOL FEEDSTOCK) COAL

	Hat Creek[a] (Lignite to Sub-bituminous)	South African[b] (Lignite to Sub-bituminous)
Proximate Analysis (% dry basis)		
Moisture	24.0	8.0
Ash	23.7	- c
Volatile Matter	25.8	-
Fixed Carbon	26.5	-
Ultimate Analysis (wt %)		
Carbon	48.1	52.4
Hydrogen	3.7	2.6
Oxygen	15.53	11.7
Nitrogen	0.88	1.2
Sulphur	0.57	0.43
Ash	31.22	31.6
Major Elements (%)		
Aluminum	3.1	4.7
Calcium	0.54	1.6
Chlorine	<0.01	7.0
Iron	1.02	1.1
Potassium	0.15	0.1
Magnesium	0.20	0.3
Sodium	0.19	0.2
Silicon	-	7.9
Titanium	0.24	-

a = proximate and ultimate analysis from ref. (5), trace and minor elements from refs. (6) and (7).

b = from ref. (8).

c = not determined

TABLE 3-1 (Continued)

Trace Elements (ppm) [d]	Hat Creek	South African
Ag	3.1	-
As	3-20	2.5
B	5.76	100
Ba	0-150	-
Be	0-19	2-3
Cd	7.1	<0.1
Ce	15.2	150-200
Co	0-18	-
Cr	0-150	-
Cu	10-72	-
F	-	100
Hg	0-4	<0.1
Li	37-1000	-
Mn	29.3-41.2	500
Ni	37.1	30-50
Pb	0.4	10-20
Sb	0.7	<0.5
Se	0.1-0.4	0.3
St	30-340	-
Th	0-4	-
V	30-150	300-500
Zn	0-52	-
Zr	476	-

d = values given as average or range

b) Scotiacoal Synfuels Project

A reasonable similarity was identified between north coast Cape Breton (Sydney) coal and Illinois No. 6 coal. The latter coal has been extensively tested in both the H-Coal and Texaco (German and U.S. versions) processes. An analysis of Donkin-Morien Reserve coal, which is currently being developed for several potential uses including coal conversion in Nova Scotia, was not available. However, this reserve is an eastern extension of the Sydney coalfield for which data exists. Therefore, based on the best available coal information, environmental data generated by the processing of Illinois No. 6 coal in the H-Coal and Texaco processes is emphasized in this report. It should be noted, however, that there is considerable variance in trace element levels between the coals. Table 3-2 presents a comparative analysis of Sydney and Illinois No. 6 coal.

c) Integrated Pyrolysis Liquids/Power Generation

Information on coals having been processed in the Lurgi Ruhrgas pilot units is not presently available in the literature. Therefore, data on a suitable Western and Eastern Canadian high-volatile coal, which should pyrolyze to give high liquid yields, are included for future reference. Table 3-3 presents an analysis of Alberta Plains Highvale sub-bituminous B coal which has been considered for pyrolysis/power generation processing in Western Canada. The Cape Breton Sydney coal discussed previously is representative of a high-volatile bituminous feedstock suitable for pyrolysis technology application in Eastern Canada[4] (see Table 3-2).

TABLE 3-2 COMPARATIVE ANALYSIS OF DEVCO SYDNEY COAL AND ILLINOIS NO. 6 COAL

	Sydney[a]		Illinois No. 6[b]
	Average	Range	Average
Proximate Analysis (% dry basis)			
Moisture	1.2	1-5	10.23
Ash	10.0	4-18	9.1
Volatile Matter	33.6	27-37	34.7
Fixed Carbon	56.9	52-64	45.29
Ultimate Analysis (wt %)			
Carbon	76.8	65-83.4	65.56
Hydrogen	5.1	4.8-5.8	4.76
Oxygen	4.8	2.5-6.3	11.0
Nitrogen	1.3	1.1-1.6	1.27
Sulphur	3.3	1.1-6.0	4.17
Ash	8.7	4.0-18.0	13.15
Major Elements (%)			
Aluminum	1.44		1.20
Calcium	0.19		0.93
Chlorine	0.15		0.06
Iron	1.40		1.5
Magnesium	0.08		0.04
Potassium	0.33		0.16
Silicon	-		2.45
Sodium	0.07		0.06
Titanium	0.10		0.06

a = proximate and ultimate analyses from ref. (4), major and trace elements from ref. (6).

b = proximate and ultimate analyses from ref. (8), major and trace elements from refs. (6) and (8).

TABLE 3- 2 (Continued)

Trace Elements (ppm)	Sydney	Illinois No. 6
Ag	0.7	0.02
As	33-270 (100)[c]	8.0
B	6-25 (17)	132
Ba	2-257 (35)	64
Be	1-2 (2)	0.6
Cd	-	1.4
Ce	15.5	-
Co	3-34 (10)	5
Cr	2-9 (5)	35
Cu	12.7	19
F	-	96
Hg	25-120 (66)	0.08
Li	-	-
Mn	104.5	9.5
Ni	10.8	55
Pb	5.4	23
Sb	0.5	1.2
Se	3.0	2
St	32-87 (65)	-
Th	2.0	-
V	7-28 (14)	25
Zn	13-64 (25)	147
Zr	27.1	-

c = single values and numbers in parantheses refer to average value

d = not determined

TABLE 3-3

ANALYSIS OF ALBERTA HIGHVALE SUB-BITUMINOUS B COAL

Proximate Analysis[a] (% dry basis)	
Ash	19.53
Volatile Matter	33.44
Fixed Carbon	47.03
Ultimate Analysis[a] (wt. %)	
Moisture	20.0
Carbon	48.07
Hydrogen	4.09
Oxygen	11.73
Nitrogen	0.61
Sulphur	0.19
Ash	15.67
Major Elements[b] (%)	
Aluminum	2.08
Calcium	1.23
Chlorine	<0.04
Iron	0.31
Potassium	0.03
Magnesium	0.10
Sodium	0.31
Silicon	-
Titanium	0.05

a = from ref. (9).

b = average and single values from ref. (6).

Table 3-3 (Continued)

Trace Elements[b] (ppm)	
Ag	-
As	1.09
B	1413
Ba	603
Be	0.4
Cd	7.9
Ce	14.8
Co	1.39
Cr	4
Cu	4.4
F	-
Hg	-
Li	-
Mn	71.0
Ni	6.2
Pb	7.1
Sb	<1.0
Se	<2.0
St	146
Th	3.2
V	8.0
Zn	15.9
Zr	64.3

b = average and single values from ref. (6).

4. Solid, Air, and Liquid Wastestream Characterization

From an extensive review of the available literature, which has yielded the information contained in the following sections of this chapter, significant wastestreams generated from each of the selected process commercial plant configurations have been identified and summarized below. Comments on these wastestreams are intended to highlight the major factors which may lead to significant environmental impacts. Since normalization of these plants to a common coal processing or equivalent bbl oil/day production rate is not within the scope of the study, comments on amounts of wastes generated refer to order of magnitude values. For example, a large volume would result from 1 - 100 tonne/d of waste while a very large volume would result from greater than 100 tonne/d of waste depending on its nature.

PROCESS	WASTE STREAM	COMMENTS
Sasol-Synthol (Hat Creek)	Spent Synthol Catalyst	Uncharacterized, large volume. Coke, metal and other element deposition expected. Regeneration scheme unknown.
	Spent Hydrotreater Catalyst (Optional process)	Uncharacterized, large volume. Residual coke, metals and elements after regeneration expected.
	Wastewater Treatment Sludge	Uncharacterized, large volume. High metals and soluble elements expected. Potential for organo-metallics formation.
	Ash	Very large volume.
	Storage Tank Emissions	Uncharacterized in terms of individual species. Majority of emissions have average molecular weight 100.
	Raw Gas Quench Liquor	Large volume, complex organics (phenolics, trace substituted cyclics), ammonia, dissolved solids, volatile metals. Pretreatment phenol by-product contaminated with heavy organics.
	Ash Handling Blowdown	High levels of soluble elements and some metals (Li, B, Cs, Mo, Rb, W, V, Zn).
	Hydrotreater Aqueous Fraction (Optional)	Uncharacterized, cyclic/polar organic species expected.
	Ash Disposal Site Runoff	Uncharacterized, unpredictable.
R/R Texaco Mobil MTG	Spent Methanol Synthesis Catalyst	Unregenerable, uncharacterized. Metals and oxygenated heavy organics deposition expected.

PROCESS	WASTE STREAM	COMMENTS
	Coarse Gasifier Slag	Large volume.
	Mobil MTG Aqueous Fraction	Large volume, uncharacterized for commercial unit. Pilot unit produces 0.44 wt. % low to medium molecular wt. polar organics in aqueous fraction.
	Coal Pile Runoff	Combination of high-S and metals coal, climatic conditions and very large pile inventory.
	Gas Liquid Blowdown	Total ammonia high, free strippable ammonia low due to high chlorides in Cape Breton coal. Pretreatment cost increased significantly.
H-Coal (Cape Breton)	Spent H-Coal Reactor Catalyst	Large volume, uncharacterized, regeneration/ resource recovery alternatives unknown. Highly susceptible to soluble element and metals deposition (Ca, Na, S, Ti, Fe).
	Spent Hydrotreater (H-Oil) Catalyst (Optional process)	Similar to H-Coal catalyst, regenerable. Residual coke, metals, soluble elements expected.
	Coarse Gasifier Slag	Large volume.
	Wastewater Treatment Sludge	Large volume, uncharacterized. Some metals, soluble elements expected. Potential for organo-metallic species formation.
	Storage Tank Emissions	Uncharacterized. Products are mainly naphtha and distillate containing high fraction of aromatic compounds.
	Foul Quench Water	Large volume, complex organics, ammonia (mostly bound-see Texaco gas

PROCESS	WASTE STREAM	COMMENTS
		liquor blowdown above), metals uncharacterized. Organics include phenolics, trace substituted cyclics.
	Hydrotreater Aqueous Fraction (Optional)	Uncharacterized, cyclic/polar organic species expected.
	Coal Pile Runoff	Combination of high-S and metals coal, climatic conditions and very large pile inventory.
Lurgi Ruhrgas Pyrolysis/ Power Generation	Spent Hydrotreater Catalyst	Uncharacterized, large volume. Residual coke, metals, soluble elements after regeneration expected.
	Boiler Ash	Very large volume, uncharacterized.
	Wastewater Treatment Sludge	Uncharacterized, large volume. Potential for high metals and soluble elements. Organometallics potentially present.
	FGD Sludge (Optional)	Large volume, uncharacterized. Potential for high volatile metals (As, Pb, Hg, Se) content.
	SO_2	Significantly higher emissions from boiler with controls than coal conversion with controls. High-S Eastern coals pose greater emissions problem.
	Storage Tank Emissions	Uncharacterized. Liquid products highly aromatic in character.
	Quench Liquor	Uncharacterized, large volume. Pretreatment for phenol removal required. By-product phenol contaminated with heavy cyclic/polar

PROCESS	WASTE STREAM	COMMENTS
		organics. Some volatile metals, soluble elements with complex organics.
	Hydrotreater Aqueous Fraction	Uncharacterized, cyclic/ polar organics expected.
	Ash Disposal Site Runoff	Uncharacterized. Unpredictable.
	Coal Pile Runoff	Significant stream in Eastern Canada setting (see H-Coal process coal pile runoff).

4.1. Solid Waste Characteristics

4.1.1. Sasol-Synthol (Hat Creek) Solid Wastes

Sasol-Synthol process modules, in the configuration proposed for the Hat Creek Project, are depicted in Figure 4-1. Solid waste streams are identified as combined gasifier and power plant discharge ash, spent Synthol catalyst, spent filter media, and combined wastewater treatment sludge. Due to the low level of sulphur in the coal, flue gas desulphurization (FGD) would not likely be required in a plant processing Hat Creek coal. The amount of FGD sludge which would be produced if discharge requirements necessitated flue gas scrubbing has, however, been determined. Discharge mass flow rates for major solid waste streams generated by a Hat Creek liquefaction plant, including power plant ash and optional FGD processing sludge, are shown in Table 4-1. The available data on the characteristics and mass flow rate of solid waste streams are presented below.

Discharge Ash

The composition of Lurgi gasifier ash generated from the processing of eight different coals, including SASOL I feedstock, is shown in Table 4-2. The analyses represent gasifier ash before contact with water for cooling and transport operations. Information on gasifier ash soluble species leached into the ash handling water is given in Section 4.3.1. of this report. The fraction of trace elements in the gasifier feed coal which are ultimately retained in the gasified ash is presented in Table 4-3.

The composition of the power plant bottom and fly ash which would be combined and discharged with the gasifier ash is given in Table 4-3. The date has been generated from testing of bulk samples of Hat Creek coal to provide design

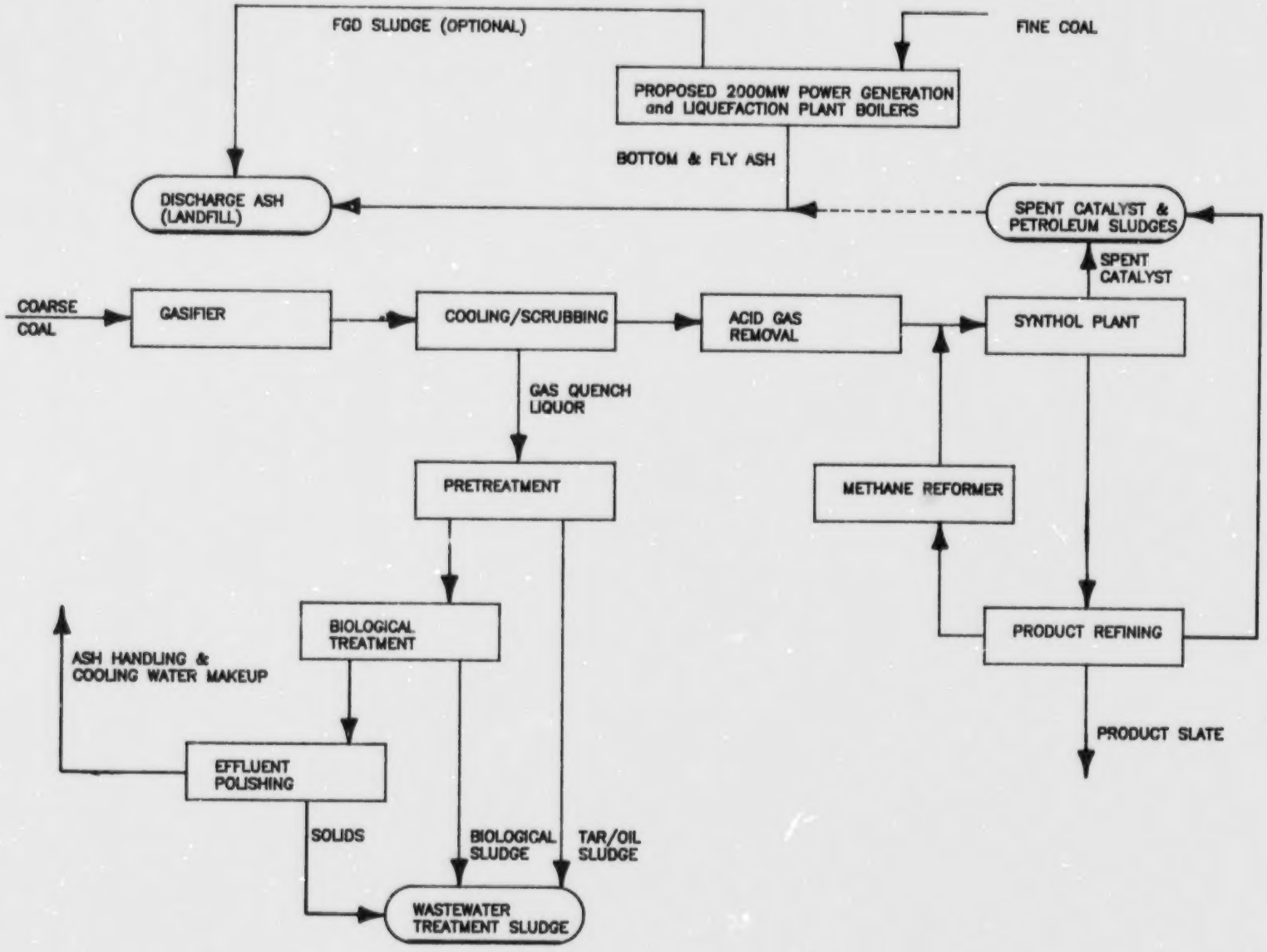


FIG. 4-1 PROCESS MODULES GENERATING SOLID WASTE IN THE SASOL-SYNTHOL (HAT CREEK) PROCESS

information for a proposed thermal electric power plant. The exact conditions under which the information was generated is, however, unknown and therefore the data should be viewed with caution. The presence of air pollution control equipment and the method of ash handling, especially with regard to water usage, may significantly affect the final properties of the discharge ashes.

Spent Synthol Catalyst

The iron-based Fischer-Tropsch synthesis catalyst must be periodically replaced to maintain activity and balance attrition losses. From a single SASOL I-type Synthol reactor processing 793,000 std m^3/hr CO and H_2, the spent catalyst production rate has been reported at 6,900 tonnes/year. Catalyst losses strictly through attrition are reported at 1,360 tonnes/year[10]. At SASOL I, the Synthol reactors are apparently shut down every 50 - 60 days for catalyst replacement generating approximately 725 tonnes of spent catalyst per reactor per cycle. It is not known if this catalyst or the attrition fines are regenerated, processed for resource recovery, or discharged as is. Any improvements made at the SASOL II operation are also unknown at this time.

Catalyst contaminants would include coke, sulphur and metals. The spent catalyst would likely be considered as a hazardous waste if no regeneration or chemical fixation/solidification were applied prior to disposal.

Spent Filter Media

At SASOL I, the gas quench liquor undergoes tar-oil separation and is passed through a sand filter for suspended solids removal prior to processing in the Phenolsolvan unit for phenol recovery. Accumulation of residual tars and oils

very likely necessitates periodic replacement of the filter media. The characteristics and frequency of replacement of spent filter media is not currently available[8].

Combined Wastewater Treatment Sludge

Information on the characteristics of combined wastewater treatment sludge, including process water treatment, plant washdown and chemical cleaning, sanitary sewage, and petroleum sludges, is not currently available. These sludges can either be landfilled separately or together along with the gasifier and power plant boiler ash.

It is anticipated that these sludges, when combined, would be designated as hazardous due to potentially high levels of metals and high molecular weight organic species particularly in the biological and petroleum sludges[11]. Therefore, landfilling of these sludges in a separate and specially-designed impoundment along with spent catalysts would likely be recommended. Readily combustible sludges, such as tar/oil separator bottom sludge or storage tank bottoms, could be burned in a specially-designed incinerator. In this case, it would be feasible to feed biological sludges to the same unit for disposal.

TABLE 4-1

SASOL-SYNTHOL (HAT CREEK) SOLID WASTES GENERATION

Process Module	Solids Generated (tonne/day)	
	Dry	Wet as discharged
Gasifier Ash and Spent Synthol Catalyst[a]	14200	19700
Power Plant Bottom Ash[b]	2070	2590
Power Plant Fly Ash[b]	8274	10340
(2000 MW) Power Plant FGD Sludge[b]	530	902
Liquefaction Plant FGD Sludge[a]	---	670
Liquefaction Plant Wastewater Treatment Sludge (combined)[a]	58	1834
Spent Filter Media	N.A.	N.A.

a = calculated from discharge over 30 year plant life, ref. (5).

b = ref. (7).

TABLE 4-2 ELEMENTAL COMPOSITION OF ASH PRODUCED BY GASIFICATION OF VARIOUS COALS IN LURGI GASIFIERS[8]

COAL TYPE/ORIGIN	SUBBITUMINOUS MONTANA/ROSEBUD	BITUMINOUS ILLINOIS #6	BITUMINOUS ILLINOIS #6	BITUMINOUS ILLINOIS #5	BITUMINOUS PITTSBURGH #8	BITUMINOUS SO. AFRICAN	LIGNITE N. DAKOTA	LIGNITE N. DAKOTA
Production Rate, kg/kg (dry basis)	0.12	0.10	-	.092	.081	0.31	0.1	0.1
Major Elements (%)								
Al_2O_3	17.7	20.5	20.5	18.1	20.7	28	-	24
CaO	8.3	2.1	2.3	3.9	3.0	7	-	26
Fe_2O_3	11.2	17.2	20.5	19.7	15.0	5	-	11
K_2O	-	-	1.8	-	-	-	-	0.6
MgO	3.9	1.0	0.6	0.7	0.7	1.7	-	7
Na_2O	-	-	0.3	-	-	-	-	8
SiO_2	46.8	49.6	49.3	46.1	43.6	52	-	25
TiO_2	-	-	1.0	-	-	-	-	0.6
SO_3	1.7	1.3 - 1.5	1.5	0.6 - 1.2	0.8	0.2	-	3.1
C	6.5	3.2 - 5.4	-	2.0 - 3.8	7.6	-	-	-
N	-	0.05	-	0.04	-	-	-	-
Cl	0.015	-	0.01	-	-	.01	-	.007
Trace Elements (mg/kg)								
Ag	.23	-	<0.4	-	-	-	0.7	1
As	26	0.1	3	0.3	-	1 - 2	60	74
B	380	622	355	673	-	100 - 150	<1500	1680
Ba	1900	-	950	-	-	-	12000	8270
Be	2.8	14	12	20	-	<0.5	5	6
Br	-	-	<1	-	-	<.1	-	3
Cd	2.4	<0.3	<1.6	0.3	-	<0.1	<1	0.5
Ce	-	-	140	-	-	200 - 400	-	190
Co	4.3	0.4	34	0.4	-	-	10	13
Cr	440	750	212	592	-	-	40	140
Cs	-	-	11	-	-	-	-	.9
Cu	130	239	57	273	-	-	50	27
F	600	5	<10	5	-	150	230	191
Ga	-	-	26	-	-	-	-	53
Ge	-	-	7	-	-	-	-	2
Hg	.03	.04	.05	.016	-	-	<.1	.055
Li	85	-	42	-	-	-	60	45
Mo	200	6	30	8	-	-	4	12
Mn	790	200	1859	305	-	2000	-	760
Ni	200	456	89	452	-	150 - 200	25	25
P	-	-	87	-	-	-	-	3500
Pb	40	96	45	200	-	50	200	58
Pb	-	-	162	-	-	-	-	35
Sb	6.2	0.2	4.2	19	-	<0.5	1	33
Sc	-	-	29	-	-	-	-	4
Se	2.2	-	<1	-	-	-	1.5	0.5
Sh	3.7	-	-	-	-	-	12	4
Sr	-	-	370	-	-	-	-	12900
Te	-	-	-	-	-	-	-	0.1
U	13	-	17	-	-	-	6	7
V	91	301	184	181	-	1000	70	150
W	-	-	1.5	-	-	-	-	2
Y	-	-	-	-	-	-	-	320
Zn	32	-	400	-	-	-	0.5	10
Zr	-	469	170	1600	-	-	-	520

TABLE 4-3

PERCENTAGE OF TRACE ELEMENTS IN FEED COAL RETAINED WITH DISCHARGE LURGI ASH

(based on feed coal concentration)

Element	Percent in Ash[a] (S. African sub-bituminous coal)
Arsenic	36 (50)[b]
Boron	36 (50)
Lead	180 (99.99)
Mercury	40 (1)
Selenium	(50)
Antimony	40
Beryllium	1
Cadmium	40
Chlorine	51
Fluorine	54
Manganese	154
Nickel	154
Vanadium	72

a = ref. (12).

b = data in parentheses from theoretical disposition model based on mass flow balance, ref. (13).

TABLE 4-4 POWER PLANT BOTTOM AND FLY ASH COMPOSITION (HAT CREEK COAL)[14]

Component	Bottom Ash	Fly Ash
Aluminum (%)	14.0	14.3
Calcium	1.43	1.58
Carbon	0.80	0.72
Iron	7.19	5.17
Magnesium	0.98	0.99
Phosphorus	0.12	0.12
Potassium	1.39	1.28
Silicon	25.5	26.4
Sodium	0.22	0.35
Sulphur	0.10	0.11
Titanium	0.56	0.60
Antimony (mg/kg)	2.3	4.8
Arsenic	6.5	30.9
Barium	290	495
Beryllium	2	1
Bismuth	9.1	1.1
Boron	50	100
Bromine	N.D.	N.D.
Cadmium	1.3	1.8
Cerium	54	59
Cesium	N.D.	N.D.
Chlorine	N.D.	11
Chromium	198	147
Cobalt	13	11
Copper	1430	720
Europium	2	2
Fluorine	22	29
Gadolinium	N.D.	N.D.
Gallium	40	40
Germanium	N.D.	N.D.
Gold	N.D.	N.D.
Hafnium	7.3	8.1
Iodine	2.0	1.5
Lanthanum	25	26
Lithium	52	55
Lead	1.1	26
Manganese	570	300
Mercury	0.116	0.107
Molybdenum	15	14
Nickel	30	42
Niobium	N.D.	N.D.
Palladium	N.D.	N.D.

TABLE 4-4 (Continued)

Component	Bottom Ash	Fly Ash
Radium (pCi/g)	2	4
Rubidium	N.D.	N.D.
Samarium	5.4	5.7
Scandium	25	26
Selenium	15	5.2
Silver	0.2	0.2
Strontium	170	365
Tantalum	1.7	1.2
Thallium	N.D.	N.D.
Thorium	8	8
Tin	N.D.	N.D.
Tungsten	1.8	2.8
Uranium	0.8	1.5
Vanadium	270	317
Ytterbium	4.0	5.1
Yttrium	50	55
Zinc	165	159
Zirconium	160	160

N.D. = Not Determined

4.1.2. R/R Texaco-Mobil MTG Process Solid Wastes

At present, environmental data from the R/R Texaco Oberhausen (German) pilot-plant is not available. However, trials on Illinois No. 6 coal have shown the overall operational characteristics of the Oberhausen and U.S. Montebello Texaco pilot units to be very similar. Table 4-6 presents a comparative analysis of operational performance of both pilot units processing Illinois No. 6 coal. The overall thermal efficiency of the R/R Texaco process is significantly higher than the U.S. process configuration. This difference is attributed exclusively to waste heat recovery from the raw gas before quenching.

R/R Texaco-Mobil MTG process modules generating solid wastes are depicted in Figure 4-2. Solid waste streams are identified as gasifier coarse slag, shift conversion spent catalyst, and combined wastewater treatment sludge. A summary of solid waste emissions from an R/R Texaco-Mobil MTG plant processing 21,722 tonne/d of Illinois No. 6 coal is shown in Table 4-7. This data has been generated from the conceptual design for an R/R Texaco-Methanol synthesis facility shown in Figure 4-9, Section 4.2.2. The available data on the characteristics of the solid wastes are documented below.

Gasifier Coarse Slag

Quenched slag from the Texaco gasifier is classified as coarse and fine slag and is separated when discharged by physical screening. The screen opening is approximately 1.6 to 3.2 mm.

The fine slag accumulates higher concentrations of metals vaporized in the gasification environment due to fact that

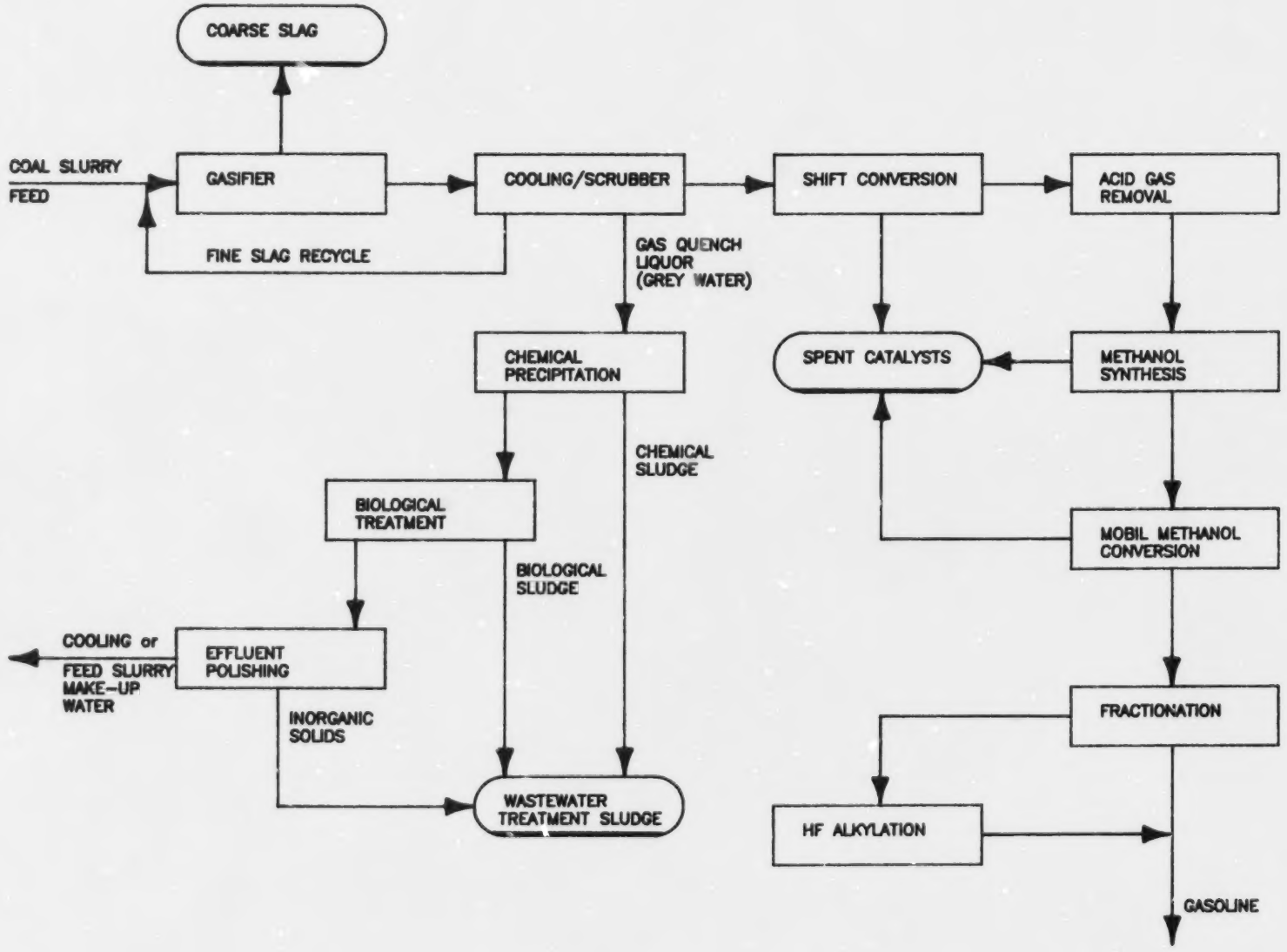


FIG. 4-2 PROCESS MODULES GENERATING SOLID WASTE IN THE R/R TEXACO-MOBIL MTG PROCESS

metal adsorption is increasingly preferred on increasingly fine particles. Table 4-8 shows the quenched fine and coarse slag characteristics for Illinois No. 6 and Kaiparowits coal processed in the Montebello pilot-plant. In most cases, the carbon content of the fine slag is high enough to warrent recycling to the gasifier.

Spent Catalyst

While specific data regarding spent catalysts in a R/R Texaco-Mobil MTG plant was not available, some data for a conceptual Lurgi-Mobil MTG plant has been published[15]. The plant is scaled to process 14,500 tonne/d of Wyodak coal in the gasifiers. In this case, 330 m^3/year of spent shift conversion catalyst, 350 m^3/year of methanol synthesis catalyst combined with zinc oxide sulphur guard, and 580 m^3/year of Mobil gasoline synthesis catalysts are projected to be discharged with other plant solid wastes. Shift conversion and Mobil-MTG catalysts undergo periodic controlled air oxidation regeneration while methanol synthesis catalyst is used once then discharged.

If the Lurgi process is replaced with the Texaco process in the above scheme, it can be anticipated that while spent shift catalyst generation may be somewhat reduced due to very few organic species in the Texaco raw gas, spent methanol and gasoline synthesis catalyst generation should remain essentially the same since they follow a raw gas purification step. More detailed information is required to verify these predictions.

The potential for severe environmental impact by spent shift and gasoline synthesis catalysts may be significantly reduced by passing these catalysts through the regeneration process prior to disposal. The non-regenerable methanol synthesis catalyst contaminated with sulphur compounds,

metals and heavy organic material may be classified as hazardous if discharged without prior treatment or chemical fixation.

Combined Wastewater Sludge

Information on the characteristics of combined wastewater treatment sludge, including process water treatment, plant washdown and chemical cleaning, sanitary sewage and petroleum sludges, was not available. These sludges would either be landfilled separately or combined with the coarse slag and steam generation boiler ash. It has been assumed that readily combustible sludges, such as product storage tank bottoms, would be burned in a specially designed incinerator. Biological sludge could also be fed to such an incinerator.

As reported in Section 4.3.2., Table 4-33. trace element levels in process water are not significantly increased during its use and final release as gas liquor blowdown from the gasifier raw gas cooling system. This fact, and the fact that a chemical precipitation stage for particulate removal preceeds biological treatment, suggests that the biological sludge emanating from process wastewater treatment will contain relatively low levels of heavy metals.

All solid wastes classified as hazardous would be landfilled, with or without prior fixation, in a specially designed facility. Leachates from such a facility would be collected and treated separately or returned to the process wastewater treatment system. Those wastes likely to be classified as hazardous are petroleum sludges, such as spent adsorbents, and process washdown and chemical cleaning sludges from equalization or holding tanks. These wastes may, therefore, be segregated in order to reduce the size of the hazardous landfill facility.

TABLE 4-6 COMPARATIVE PERFORMANCE OF GERMAN AND U.S. TEXACO PROCESS PILOT PLANTS PROCESSING ILLINOIS NO. 6. COAL (16)

	MONTEBELLO (U.S.)	OBERHAUSEN (GERMAN) (2 runs)	
Coal Feed Rate (tonne/h dry)	0.64	6.4	4.5
Coal Heating Value (kJ/kg dry)	5,550	5,930	5,930
Slurry Concentration (wt. % solids)	60	59	57
O_2/Coal Ratio (kg/kg dry coal)	0.93	0.93	1.03
Carbon Conversion (%)	99	95	98
Cold Gas Efficiency (%)	68	67	65
Overall Thermal Efficiency	68	82	84
Raw Gas Composition (Vol. %)			
CO	42.2	41.2	39.8
H_2	34.4	36.5	35.1
CO_2	21.7	20.7	23.6
H_2 and COS	1.3	1.1	1.1
N_2	0.4	0.5	0.4

TABLE 4-7 SUMMARY OF SOLID WASTE EMISSIONS FROM R/R TEXACO-MOBIL MTG PROCESS [17]

(Basis: 21,722 tonne/day, Illinois No. 6 Feedcoal)

DESCRIPTION	EMISSION RATE (TONNE/DAY)	COMMENTS
Steam Generation Ash	483	Non-hazardous waste
Coarse Slag	6739	Non-hazardous waste
Settled Coarse Slag	2022	Non-hazardous waste
Spent Catalysts	N.A. (see text)	Potential hazardous waste
Water Treatment Sludges	N.A.	Characteristics unknown
Petroleum Sludges	N.A.	Hazardous waste
Elemental Sulphur	584	Stockpiled or sold as by-product

N.A. - Not Available.

TABLE 4-8 TEXACO (MONTEBELLO) GASIFIER SLAG ANALYSIS[18]

	ILLINOIS NO. 6 FEED COAL		KAIPAROWITS FEED COAL	
	COARSE SLAG	FINE SLAG	COARSE SLAG	FINE SLAG
MAJOR COMPONENTS (wt. %)				
Ash	99.30	65.14	99.91	81.52
Carbon	1.79	32.39	0.40	17.21
Hydrogen	0.023	0.31	0.16	0.01
Nitrogen	0.006	0.48	0.08	0.26
Sulphur	0.83	2.08	0.0	0.09
TRACE ELEMENTS (mg/kg)				
Antimony	0.9	0.9	<0.5	<0.5
Arsenic	15.0	20.5	30	22
Barium	378	301.5	3200	2650
Beryllium	7.5	6.6	63	2.3
Boron	-	-	6	40
Chlorine	10	44	0.32	300
Cadmium	5.0	6.7	2100	0.40
Chromium	1790	842	13	1450
Cobalt	125	85.5	49	9.7
Copper	81	90	80	48
Fluorine	45	210	0.9	230
Lead	30	47	380	2.8
Manganese	614	525	0.18	300
Mercury	0.15	0.095	2.3	0.28
Molybdenum	64	98.5	39	7.6
Nickel	229	267	0.76	34
Selenium	14	17.5	<0.3	4.0
Silver	0.1	0.2	1.0	0.6
Thallium	0.3	0.3	180	8.4
Vanadium	340	280	13	140
Zinc	65	425		26

4.1.3. H-Coal Process Solid Wastes

Process modules generating solid wastes from a fully-integrated H-Coal liquefaction plant are depicted in Figure 4-15, Section 4.3.3. The basis for the analysis is the H-Coal Breckinridge Project Draft Environmental Impact Statement for a facility processing 21,389 tonnes/d of run-of-mine (ROM) coal to approximately 50,000 bbl/d of liquid petroleum products[19]. The overall flow diagram for the plant is shown in Figure 4-3.

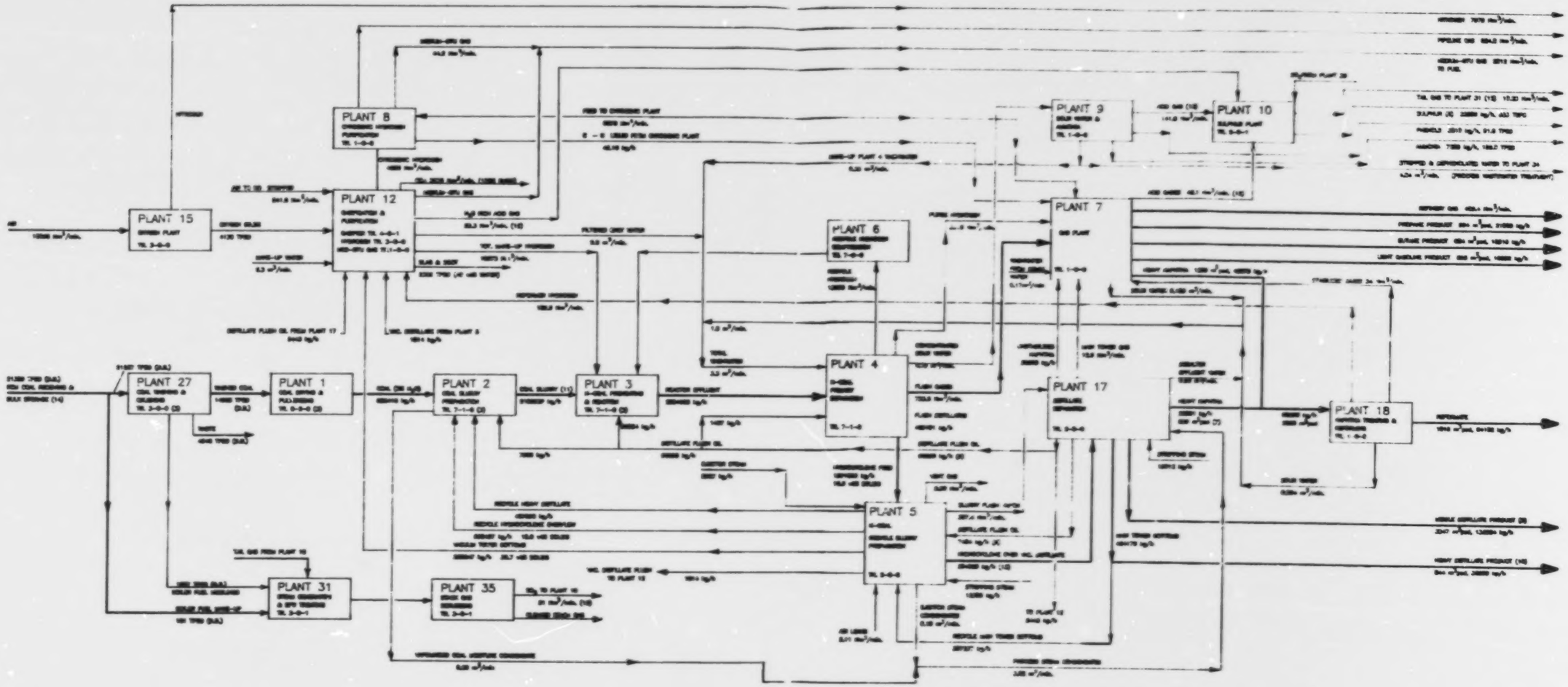
A number of major differences will exist between the Breckinridge Project and the proposed Scotia Coal Synfuels Project. These differences, which will effect the overall environmental impact, arise from consideration of the following factors:

1) As of October 1982, the Scotia Coal Synfuels plant conceptual design calls for 5,000 tonne/d of feed coal from the Donkin-Morien reserve.

2) The feed coal from the Donkin Reserve may be washed at the Victoria Junction coal washing plant rather than the plant site.

3) Differences in environmental control guidelines applicable at the plant site may result in large differences in effluent control strategies implemented at the two proposed projects.

4) Recent advances in H-Coal process technology coupled with differences in markets for finished products from the respective plants may result in major differences in process operation which will affect wastestream



NOTES:

1. FLOW QUANTITIES ARE BASED ON THE HRI SIMULATION DATED JULY 22, 1980. THE PLANT PRODUCES A TOTAL OF 8323 m³ pcd OF C_3+ PRODUCTS EXCLUDING PHENOLS.
2. FINAL PRODUCTS HAVE BEEN NORMALIZED BASED ON PDU RUN 5, PERIOD 29, H-COAL REACTOR YIELDS. THE TOTAL PRODUCT FROM SIMULATION IS 705 kg/h LESS THAN THE TOTAL PDU YIELDS DUE TO COMPUTER CONVERGENT LIMITATIONS.
3. TRAIN NOS. (A-B-C) REPRESENT THE FOLLOWING:
   A = NO. OF OPERATING TRAINS
   B = COLD SPARES
   C = HOT SPARES
4. D.B. = DRY BASIS
5. SOUR WATER & WASH WATER FLOWRATES ARE BASED ON 8 wt% SALTS IN CONCENTRATED SOUR WATER.
6. SULPHUR BALANCE BASED ON ACTUAL SULPHUR AMOUNT USED IN HRI SIMULATION & HYDROGEN PLANT DESIGN. BECHTEL SULPHUR PLANT DESIGN IS 638 TPSD.
7. PLANT 17 ADJUSTED TO GIVE HEAVY NAPHTHA SIDE-DRAW FROM MAIN TOWER BASED ON HRI SIMULATION DATED AUG. 10, 1980.
8. MIDDLE DISTILLATE PRODUCT REDUCED TO REFLECT PRODUCTION OF PHENOLS. PHENOLS MAY BE BLENDED INTO MID-DISTILLATE IF NO MARKET DEMAND EXISTS.
9. FLUSH OIL RATES SHOWN BASED ON 7/22/80 HRI SIMULATION. UPDATED RATES OBTAINED FROM PUMP VENDORS GIVEN IN PLANT 39 DESIGN BASIS.
10. HEAVY DISTILLATE PRODUCT REDUCED BY 6351 kg/h FROM NORMALIZED PDU RATE TO COMPENSATE ADDITIONAL FLUSH OIL REQUIRED.
11. FOR CONSISTENCY WITH 7/22/80 HRI SIMULATION, FLOWRATE FOR THIS STREAM INCLUDES VAPORIZED COAL MOISTURE CONDENSATE.
12. FLOWRATES BASED ON SULPHUR COMPOUNDS ONLY.
13. FLOWRATE ADJUSTED FROM 7/22/80 HRI SIMULATION TO MATCH ACTUAL DESIGN FLOWRATES FOR 7/30/80 VAC. TOWER BOTTOMS & VAC. DISTILLATE FLUSH OIL.
14. RUN-OF-MINE COAL FEED RATE SHOWN IS ON DRY BASIS. PLANT 27 DESIGN COAL INCLUDES 4 wt% SURFACE MOISTURE PLUS 7 wt% INHERENT MOISTURE FOR A TOTAL OF 11 wt%.
15. TPSD = METRIC TONS PER STD. DAY
16. $Nm^3/min.$ = $m^3/min.$ FLOW AT STP.

FIGURE 4-3 OVERALL BLOCK FLOW DIAGRAM FOR THE H-COAL BRECKINRIDGE PROJECT.

characteristics (eg. gasification of vacuum tower bottoms versus disposal or alternate processing).

The data to be presented in this report concerning air, water, and solid waste discharges from a full-scale H-Coal liquefaction facility will, therefore, be based on the Breckinridge Project under the assumption that these data represent the only complete evaluation currently available and that such an evaluation is useful in establishing points of waste discharge and order-of-magnitude wastestream flowrates and characteristics. Pertinent data from related processing of Cape Breton coals is also included where applicable.

Solid wastestreams are identified as: coal cleaning refuse, gasifier slag, boiler bottom and fly ash, flue gas scrubber sulphate waste, raw water treatment filter cake, spent coal washing medium (flotsam) and plant refuse, process wastewater treatment sludge and non-process wastewater treatment sludge. Discharge flowrates and characteristics of the solid wastes identified above for the Breckinridge Project are summarized in Table 4-9.

All spent catalyst streams are assumed to be regenerated off-site by an independent contractor. If spent catalysts were regenerated on-site, as may be required at the Cape Breton project site, the fully spent portion would likely require special handling or landfilling in a hazardous waste facility. Information on the regeneration and disposal of spent liquefaction, hydrotreating, platforming and other catalysts utilized in liquefaction product upgrading processes was not available.

Combustible petroleum sludges, such as API separator sludge and storage tank bottoms, are fed to a fluidized-bed incinerator for disposal. Spent chemical cleaning agents and

other non-combustible chemical liquid or solid wastes are discharged to the hazardous waste landfill. Characterization and flow data are not available for these streams. Although incineration of biological sludges along with combustible sludges should be feasible, all bio-sludges from the Breckinridge Project are to be landfilled on the hazardous waste facility.

Further detailed data on the projected characteristics of several major solid waste streams identified above are documented below:

Texaco Gasifier Coarse Slag

In the H-Coal process, the coal ash is separated from the liquid and gaseous products as a heavy oil slurry, and finally released as residuum bottoms from a vacuum tower. The residuum is then cooled on a metal conveyor to yield a flaked residuum solid. Available trace element data for residuum generated by the H-Coal PDU processing Illinois No. 6 coal is presented in Table 4-10.

The residuum consists of the coal ash combined with a heavy tar-like carbon residue. This stream is then gasified in a Texaco gasifier which yields mainly carbon monoxide and hydrogen and a small amount of carbon dioxide. The raw gas is shift converted to yield hydrogen in excess of 80 percent which is recycled as make-up to the coal hydrogenation reactor. Flaked residuum from the pilot plant has been tested at the Texaco Montebello pilot plant, however, only data on the testing of PDU residuum from Illinois No. 6 and Wyodak coals was available. Table 4-11 shows slag fraction production rates for several gasification tests at the Montebello pilot-plant processing H-Coal residuum.

Steam Boiler Bottom and Fly Ash

Information on the characteristics of bottom and fly ash generated from conventional firing of Devco Sydney Coal at the Glace Bay Generating Station is presented in Table 4-12. The coal has not been processed in a coal washing plant before firing in the boiler. Results from test runs of Donkin Reserve coal samples in the Victoria Junction coal washing plant and in conventional steam boilers, are not currently available. The data presented on boiler plant ashes in Table 4-9 are from firing of middlings from the coal washing plant processing Illinois No. 6 coal and a small make-up amount of ROM coal.

All solid wastes are discharged to one of two landfill sites, the majority (cited as 98 percent) being sent to a non-hazardous waste landfill. Process wastewater treatment sludge (in the form of evaporated salts and biological solids), Wellman-Lord FGD sulphate waste and chemical sludges are sent to a specially-lined hazardous waste landfill.

TABLE 4-9 SOLID WASTE CHARACTERISTICS AND QUANTITIES FOR THE H-COAL BRECKINRIDGE PROJECT[19]

SOURCE	WASTE	QUANTITY		CHARACTERISTICS	
		Dry Solids (tonne/day)	Source Total (tonne/day)	Moisture[c] % by wt.	Density[d] (kg/m^3)
Coal Brushing and Washing	Coal Refuse	6075	7798	22	1442
Gasifier	Slag	1384	2311	40	1442
Boiler Plant	Fly Ash	212	249[b]	0	1202
Boiler Plant	Bottom Ash	87	153	43	1442
Flue Gas Scrubber	Sulphate By-Product[a]	11	11	0	1121
Water Treatment	Filter Cake	22	104	79	1121
Wastewater Treatment	Filter Cake, Salts[a]	104	197	48	1121
Miscellaneous	Facility Refun, Flotsam	5	6	20	801
TOTAL		7900	10829		
NON-HAZARDOUS COMPONENT		7785	10621		
HAZARDOUS COMPONENT		115	208		

a - Tentatively defined as hazardous.

b - Includes 37 tonne/day of moisture added to dry fly ash.

c - Wet basis.

d - In-place, compacted density on a dry basis.

TABLE 4-10 TRACE ELEMENTS DETERMINED IN PDU VACUUM RESIDUUM BOTTOMS (ILLINOIS NO. 6 COAL)[20]

ELEMENT	RANGE (mg/kg)
Antimony	<1
Arsenic	1 - 2
Beryllium	1 - 2
Boron	3 - 4
Cadmium	<1
Chromium	2 - 3
Copper	1 - 2
Iron	<4
Lead	1 - 2
Manganese	2 - 3
Mercury	<1
Nickel	1 - 2
Selenium	1 - 2
Tin	<1
Vanadium	2 - 3
Zinc	2 - 3

TABLE 4-11 PRODUCTION RATES AND CARBON CONTENTS OF SLAG AND SOOT FOR TEXACO GASIFICATION OF H-COAL LIQUEFACTION RESIDUES[21]

GASIFICATION RESIDUE	FEED*			
	ILLINOIS #6 H-COAL RESIDUE		WYODAK H-COAL RESIDUE	
	RUN 1 - 2	RUN 1 - 5c	RUN W - 6	RUN W - 7
COARSE SLAG				
Carbon (wt. %)	12.6	0.50	0.5	0.45
Production Rate (dry kg/kg feed)	0.023	0.055	0.005	0.07
FINE SLAG				
Carbon (wt. %)	31.3	2.50	8.4	7.4
Production Rate (dry kg/kg feed)	0.10	0.12	0.044	0.005
SOOT				
Carbon (wt. %)	31.3	16.76	17.7	12.7
Production Rate (dry kg/kg feed)	0.145	0.029	0.072	0.017

* A total of 17 runs were performed using Illinois #6 H-Coal liquefaction residues, and a total of 8 runs were performed using Wyodak H-Coal liquefaction residues. Runs 1-2, 1-5c, W-6, and W-7 represent the extremes of slag and soot production obtained under different oxygen input rates (gasification temperatures). Oxygen input rates were as follows: 0.56 SCM/kg (9.1 SCF/lb) for Run 1-2; 0.61 SCM/kg (9.9 SCF/lb) for Run 1-5c; 0.62 SCM/kg (10.1 SCF/lb) for Run W-6; and 0.68 SCM/kg (11.1 SCF/lb) for Run W-7).

TABLE 4-12 POWER PLANT BOTTOM AND FLY ASH COMPOSITION (DEVCO SYDNEY COAL) (14)

COMPONENT	FLY ASH	BOTTOM ASH
Aluminum %	8.36	3.03
Calcium %	1.16	0.87
Carbon %	23.11	67.0
Iron %	11.9	9.46
Magnesium %	0.65	0.49
Phosphorus %	0.92	0.16
Potassium %	2.16	0.97
Silicon %	16.5	4.22
Sodium %	0.44	0.39
Sulphur %	0.25	1.57
Titanium %	0.35	0.17
Antimony (mg/kg)	8.4	6.0
Arsenic	79	633
Barium	156	100
Beryllium	N.D.	2
Bismuth	31	6.0
Boron	10	10
Bromine	11	2
Cadmium	0.04	0.07
Cerium	68	35
Cesium	N.D.	N.D.
Chlorine	5.1	4.3
Chromium	101	125
Cobalt	30	27
Copper	78	197
Europium	1	2
Fluorine	N.D.	8.1
Gadolinium	N.D.	N.D.
Gallium	N.D.	50
Germanium	N.D.	N.D.
Gold	N.D.	N.D.
Hafnium	3.5	0.8
Iodine	1.9	1.7
Lanthanum	40	23
Lithium	53	42
Lead	15	66
Manganese	490	20
Mercury	N.D.	N.D.
Molybdenum	14	24
Nickel	11	20
Niobium	N.D.	N.D.
Palladium	N.D.	N.D.
Radium (pCi/g)	2	2
Rubidium (mg/L)	N.D.	N.D.
Samarium	5.6	3.7
Scandium	12	6.5
Selenium	4.7	1.1
Silver	0.5	0.4
Strontium	340	370
Tantalum	0.8	1.1
Thallium	N.D.	N.D.
Thorium	10	5
Tin (ppm)	N.D.	N.D.
Tungsten	1.5	2.0
Uranium	0.4	N.D.
Vanadium	118	500
Ytterbium	2.2	188
Yttrium	N.D.	N.D.
Zinc	127	282
Zirconium	65	50

4.1.4. Lurgi Ruhrgas Pyrolysis/Power Generation Solid Wastes

The Lurgi Ruhrgas Pyrolysis/Power Generation Process modules generating solid wastes are depicted in Figure 4-4. Solid waste streams are identified as hydrotreating spent catalyst, boiler bottom ash/captured fly ash, and combined water treatment sludge. The available data on the characteristics of these solid waste streams are presented below:

Hydrotreating Spent Catalyst

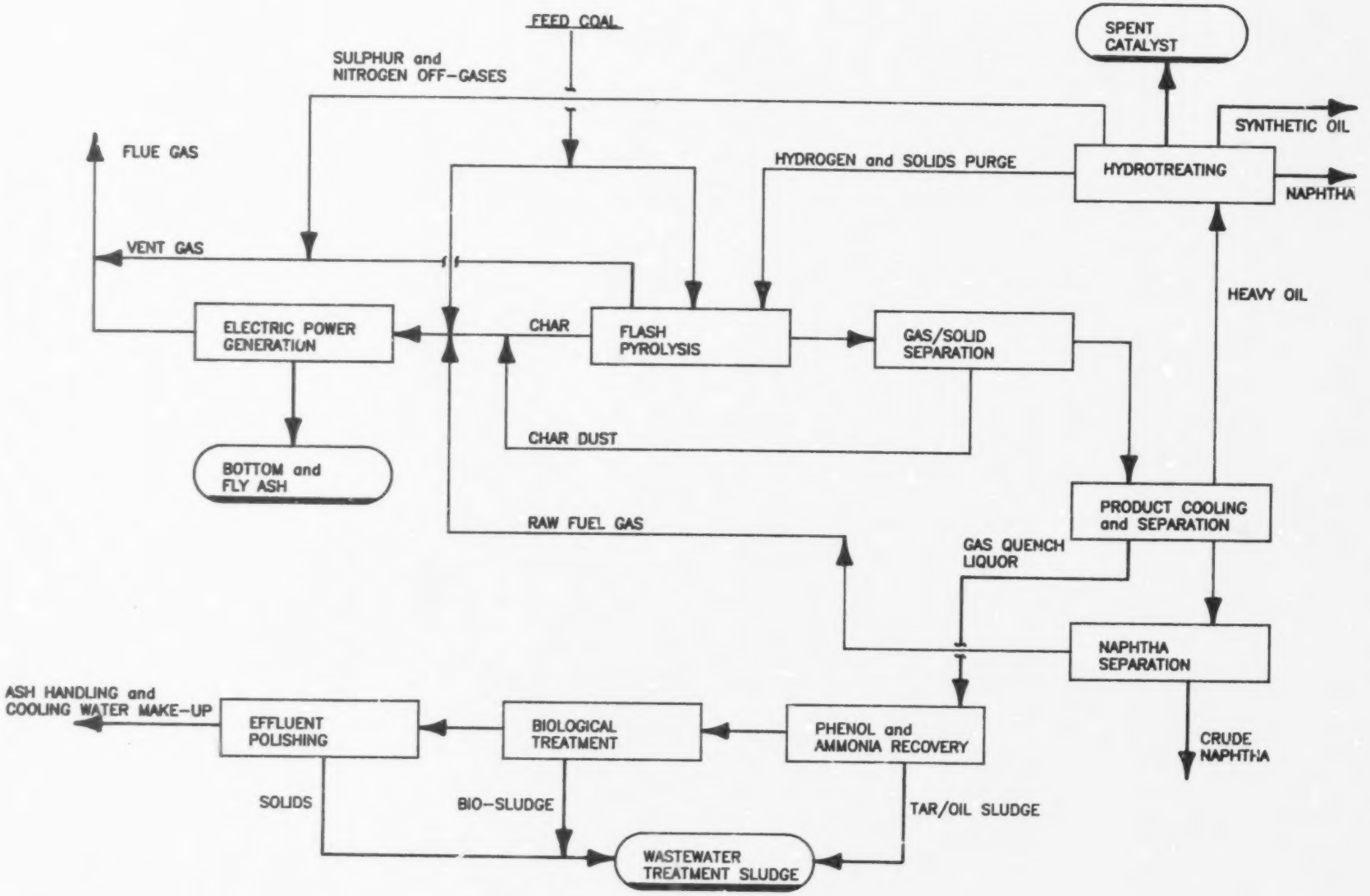
There are several processes which can be employed for hydrotreating the pyrolysis heavy oil. The H-Oil Process (Hydrocarbon Research In.) has undergone some preliminary evaluation for this purpose and will be considered here. The proprietary catalyst has been shown to be effective in removing metals, especially iron (believed to be in organometallic form) while retaining an acceptable activity level during the processing of a hydropyrolysis heavy oil at the bench-scale[22]. However, data on actual spent catalyst generation rates and contaminants are not presently known. The spent catalyst would likely be considered as a hazardous waste if released before a regeneration or treatment and would require special handling if discharged.

Boiler Bottom Ash and Fly Ash

Since the Lurgi Ruhrgas process has not, to date, been tested in the fully-integrated configuration described here, no data exists on the composition and proportions of bottom and fly ash generated from char combustion either alone or combined with coal make-up.

At least 1 to 2 percent of the ash in the pyrolyzed coal along with 7 to 8 percent coke dust is retained in the

FIG. 4-4 PROCESS MODULES GENERATING SOLID WASTE IN LURGI RUHRGAS PYROLYSIS and POWER GENERATION PROCESS (Western Canada Low-Sulphur Coal)



product tar and recycled to the pyrolyzer following the hydrotreating step. The majority of the ash remains with the product char and is fed to the boiler along with fresh feed coal and the raw product gas. In a commercial plant it is projected that modification only to the burners will be required while other conventional boiler equipment will be feasible. The composition of bottom and fly ash produced in a conventional power generation boiler on Highvale B sub-bituminous coal is presented in Table 4-13 an estimation of the ash composition from a Lurgi Ruhrgas Pyrolysis/Power Generation facility processing this coal. It should be noted, however, that burner modification can greatly influence the bottom-to-fly ash ratio, the size distribution and the corresponding trace element composition of the ash.

Combined Wastewater Treatment Sludge

Information on the characteristics of combined wastewater treatment sludge, including process and boiler raw water treatment, process wastewater treatment, sanitary sewage, plant washdown and chemical cleaning, and petroleum sludges, was not available. It is assumed that those sludges which are readily combustible, such as tank bottoms, API separator bottom sludge and oily scums from equalization and holding ponds, will be burned in specially-designed incinerators. The remaining sludges listed above may require landfilling in a hazardous waste facility. This would be due to the presence of heavy metals originating from the feed coal and/or the presence of coal tar compounds in wash and chemical cleaning wastes and petroleum sludges such as spent absorbents. Segregation of sludges designated as hazardous may, therefore be practised in order to reduce the size of the hazardous waste disposal facility.

TABLE 4-13

POWER PLANT BOTTOM AND FLY ASH COMPOSITION

(HIGHVALE B SUB-BITUMINOUS COAL)[14]

COMPONENT	BOTTOM ASH	FLY ASH
Aluminum (%)	12.8	13.0
Calcium	7.11	8.94
Carbon	2.30	0.34
Iron	2.63	2.67
Magnesium	0.50	0.70
Phosphorus	0.088	0.11
Potassium	0.76	0.69
Silicon	24.1	23.9
Sodium	1.31	1.84
Sulphur	0.06	0.13
Titanium	0.33	0.37
Antimony (mg/kg)	7.3	8.8
Arsenic	4.3	35
Barium	1950	3122
Beryllium	N.D.*	N.D.
Bismuth	2.7	6.0
Boron	100	200
Bromine	N.D.	N.D.
Cadmium	0.25	0.24
Cerium	120	150
Cesium	N.D.	N.D.
Chlorine	14	47
Chromium	110	100
Cobalt	1.3	8.3
Copper	30	49
Europium	2	2
Fluorine	25	27
Gadolinium	N.D.	N.D.
Gallium	20	60
Germanium	N.D.	N.D.
Gold	N.D.	N.D.
Hafnium	11	14
Iodine	1.9	2.0
Lanthanum	74	91
Lithium	41	47
Lead	26	58
Manganese	310	290
Mercury	0.094	0.080
Molybdenum	9	8
Nickel	10	1.6
Niobium	10	10
Palladium	N.D.	N.D.
Radium (p CI/g)	4	6
Rubidium	N.D.	N.D.
Samarium	8.6	10
Scandium	10	12
Selenium	5.5	14
Silver	0.4	0.7
Strontium	1100	1600
Tantalum	1.7	2.0
Thallium	N.D.	N.D.
Thorium	24	32
Tin	2	N.D.
Tungsten	5.8	6.7
Uranium	5.8	8.5
Vanadium	18	70
Ytterbium	4.8	6.2
Yttrium	50	50
Zinc	146	144
Zirconium	230	180

* N.D. = NOT DETECTED

4.2. Atmospheric Emissions

4.2.1. Sasol-Synthol Process Atmospheric Emissions

A comprehensive analysis of atmospheric emissions from a Sasol-Synthol plant processing Illinois No. 6 coal has been prepared by Fluor GmbH[17]. Emissions from all plant sources are given based on a conceptual plant design including emission control processes. Information on the SASOL I and Kosovo, Yugoslavia (gasification only) plant emissions is available, however, these data are obsolete due to coal processing design changes, the availability of improved pollution control technology and the inclusion of recycling and waste heat recovery for greater energy efficiency. Therefore, owing to the completeness of the data and the contemporary design basis, atmospheric emissions from the SASOL II-type plant processing Illinois No. 6 coal will be reported in this section. U.S. EPA Best Available Control Technology (BACT) guidelines have been employed in the selection of control processes.

Table 4-14 presents the summary of total atmospheric emissions for the given plant design basis. For comparison purposes, the sulphur dioxide emissions for the same plant processing Hat Creek coal is included. This value has been estimated, based on relative amounts of sulphur and the calorific values of Illinois No. 6 and Hat Creek coal.

The conceptual plant design mass balance for the coal gasification and raw gas purification section, including identification of air emission streams, is presented in Figure 4-5. Figure 4-6 presents the same information for the Synthol reactor and products upgrading section. The plant sulphur balance is presented in Figure 4-7.

Gaseous emission streams identified by number in Figures 4-5 and 4-6 are characterized in Table 4-15. Raw product, interim final product, by-product and plant chemical storage tank atmospheric emissions are presented in Table 4-16. The particulate emissions summary is given in Table 4-17.

TABLE 4-14 ATMOSPHERIC EMISSIONS SUMMARY FOR SASOL-SYNTHOL PLANT WITH EMISSION CONTROLS[17]

FEED COAL	Illinois No. 6
THROUGHPUT[a] (tonne/day)	25938
Sulphur Content (wt. %) (moisture and ash free basis)	3.48
Emissions: (kg/1,000 kg coal throughput)	
Sulphur Dioxide	3.09 (0.45)[b]
Nitrogen Oxide	2.34
Carbon Monoxide	0.32
Carbon Dioxide	1,818
Particulates	0.14
Storage Tank Emissions (kg/day)	1248

a = Total for coal conversion and steam generation.

b = Estimate for Hat Creek coal based on coal sulphur content and calorific value comparison.

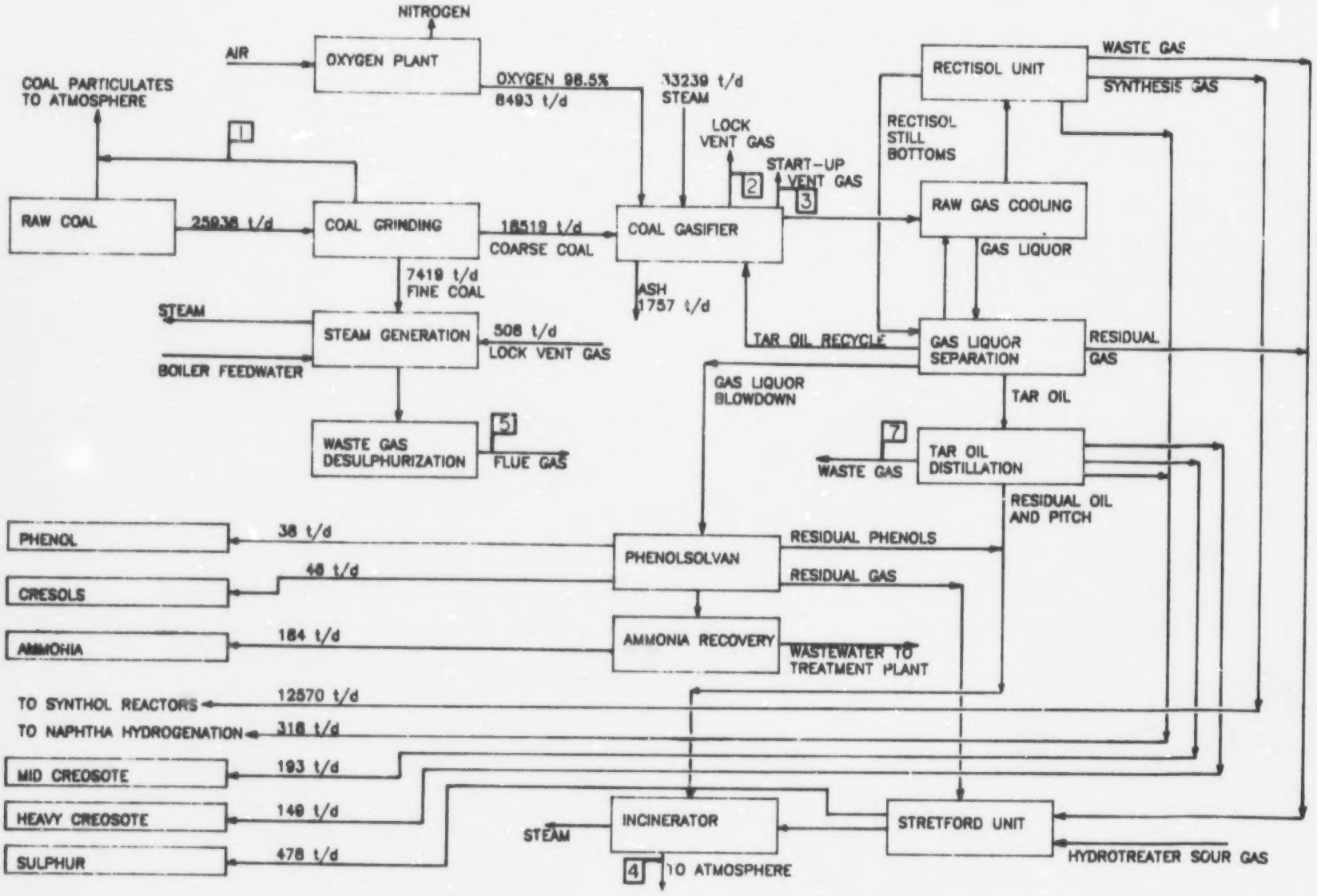


FIGURE 4-5 MATERIAL FLOW SCHEMATIC FOR THE COAL GASIFICATION SECTION OF THE SASOL-SYNTHOL PROCESS (17)

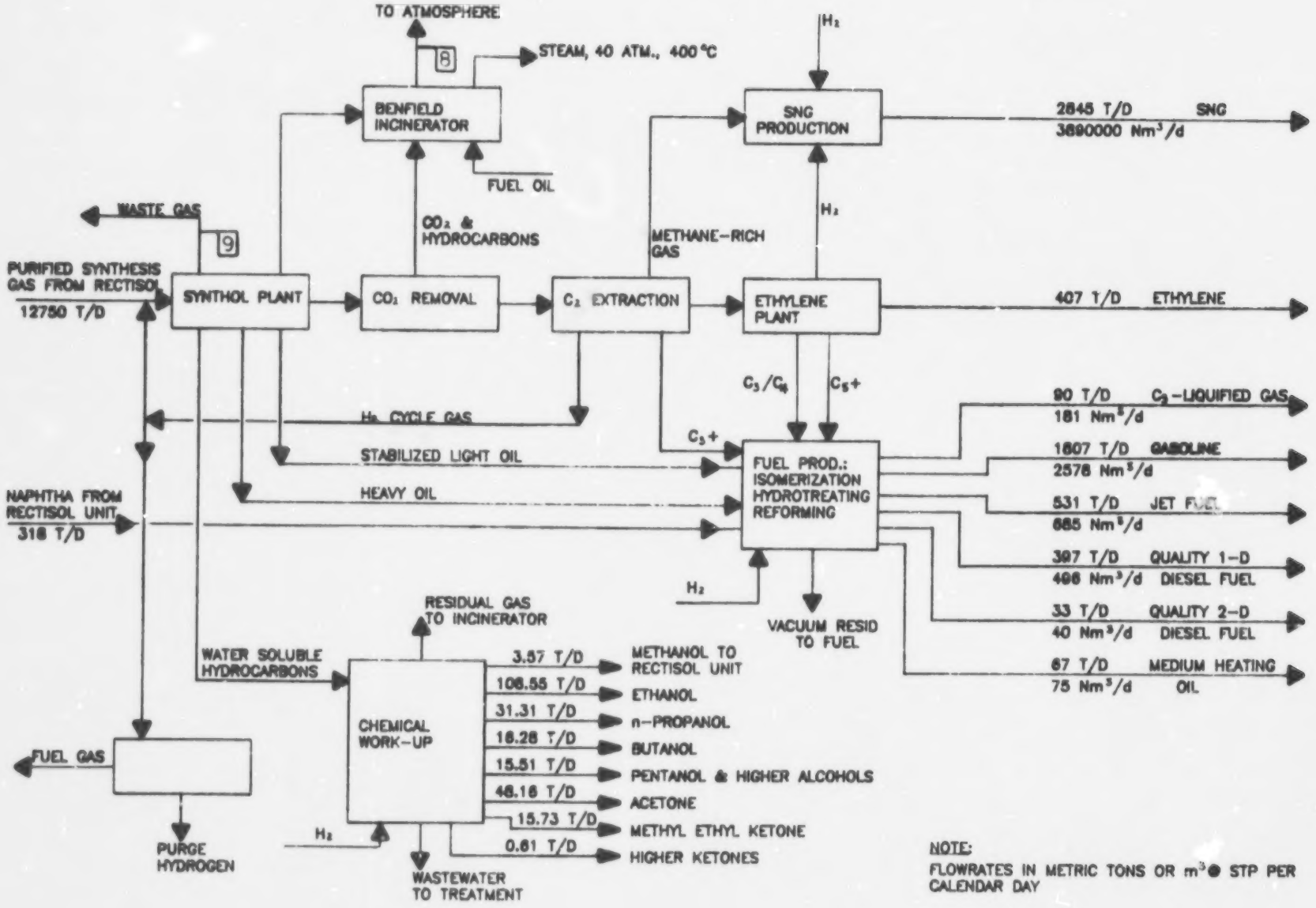
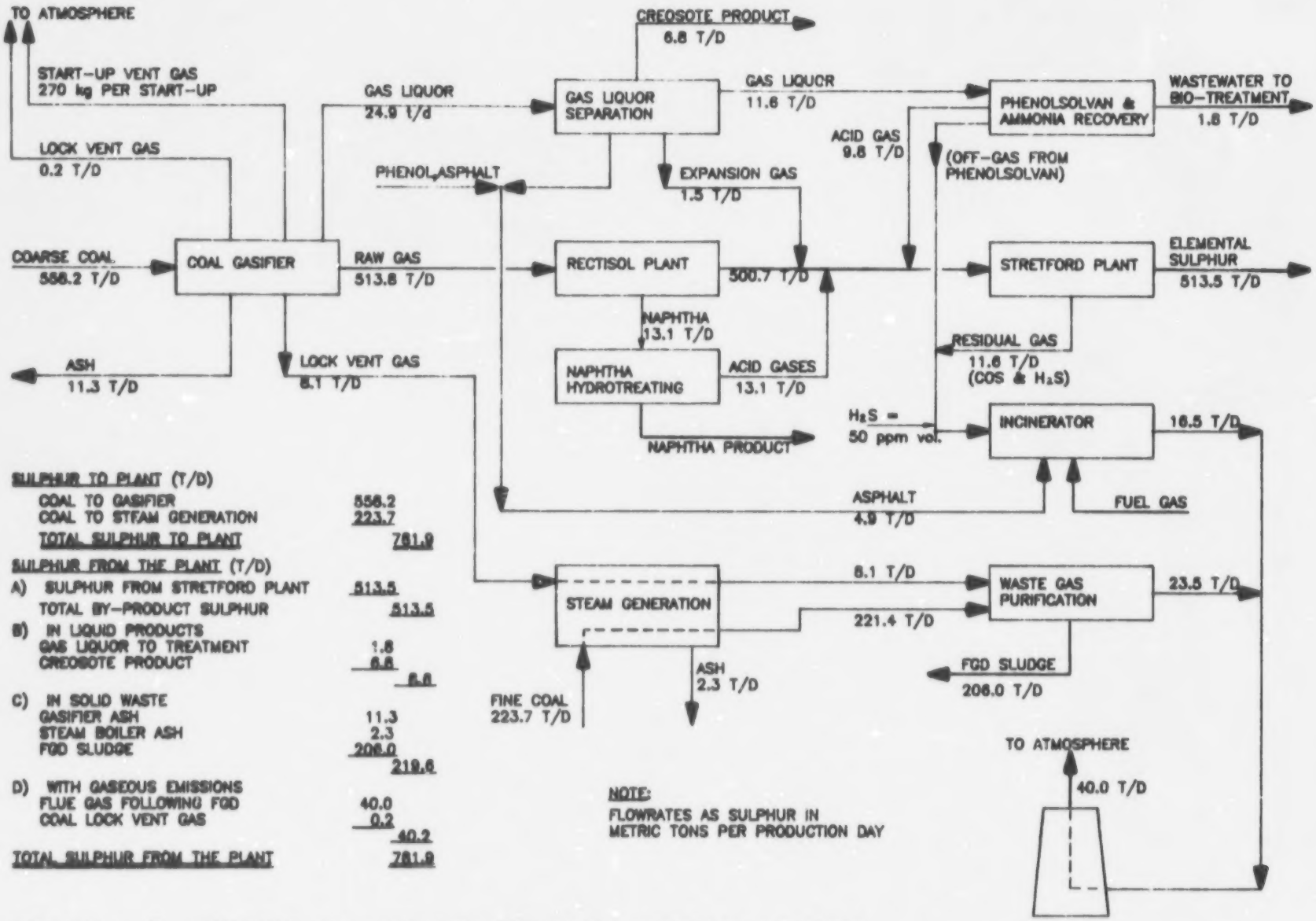


FIGURE 4-6 MATERIAL FLOW SCHEMATIC FOR THE SYNTHOL AND UPGRADING SECTIONS OF THE SASOL-SYNTHOL PROCESS (17)



SULPHUR TO PLANT (T/D)

COAL TO GASIFIER	556.2	
COAL TO STEAM GENERATION	223.7	
TOTAL SULPHUR TO PLANT		781.9

SULPHUR FROM THE PLANT (T/D)

A) SULPHUR FROM STRETFORD PLANT	513.5	
TOTAL BY-PRODUCT SULPHUR		513.5
B) IN LIQUID PRODUCTS		
GAS LIQUOR TO TREATMENT	1.8	
CREOSOTE PRODUCT	6.8	
		8.6
C) IN SOLID WASTE		
GASIFIER ASH	11.3	
STEAM BOILER ASH	2.3	
FGD SLUDGE	206.0	
		219.6
D) WITH GASEOUS EMISSIONS		
FLUE GAS FOLLOWING FGD	40.0	
COAL LOCK VENT GAS	0.2	
		40.2
TOTAL SULPHUR FROM THE PLANT		781.9

NOTE:
FLOWRATES AS SULPHUR IN METRIC TONS PER PRODUCTION DAY

FIGURE 4-7 SULPHUR BALANCE FOR THE SASOL-SYNTHOL PROCESS.

TABLE 4-15 CHARACTERISTICS OF ATMOSPHERIC EMISSIONS FROM A SASOL-SYNTHOL PLANT (17)

Reference No. (a)	1		2		3		3		4	
Stream Description	Coal Dust From Storage and Transport		Coal Lock Vent Gas		Start-Up Vent Gas (b)		Start-Up Vent Gas Directly to Atmosphere		Shetford Incinerator Waste Gas	
	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h
HCN	0	0	0	0	0	0	0	0	0	0
SO_2	0	0	0	0	0.26	127	0	0	0.06	1,376
H_2S	0	0	0.96	7	0	0	0.88	126	0	0
COS	0	0	Trace	Trace	0	0	0.02	5	0	0
Org. Sulphur	0	0	Trace	Trace	0	0	0.02	5	0	0
CH_4	0	0	9.63	34	0	0	8.92	597	Trace	1
Hydrocarbons	0	0	0.67	5	0	0	0.62	77	0	0
CO	0	0	19.67	123	0	0	18.26	2,137	Trace	7
CO_2	0	0	29.23	287	15 74	5,274	27.09	4,982	61.05	977,866
NO_x	0	0	0	0	0	0	0	0	Trace	87
NH_3	0	0	0	0	0	0	0.74	52	0	0
O_2	0	0	0	0	0	0	0	0	1.40	16,274
N_2	0	0	0.37	2	65.08	13,874	0.24	28	31.03	316,315
H_2	0	0	39.37	18	0	0	36.59	306	0	0
H_2O	0	0	0	0	18.92	2,592	6.50	489	6.46	42,301
HCl	0	0	0	0	0	0	0	0	0	0
Cl_2	0	0	0	0	0	0	0	0	0	0
Argon	0	0	0	0	0	0	0.12	20	0	0
Particulates	N/A	39	0	0	0	0	0	0	N/A	5
TOTAL	N/A		100.00		100.00	21,867	100.00	8,824	100.00	1,354,232
Volume Flowrate (m^3/h @ STP)	N/A		500		17,048		9,358		815,088	
Emission Temperature (^oC)	N/A		50		-		-		205	

a) Flow reference numbers are in accordance with material flow schematics: Figures 4- 5 and 4-6.
b) Vent gas during start-up of a gasifier during air cycle of 4 hours: after-burned gas., No. of start-up events per year: 72.
c) Vent gas during first 10 minutes of oxygen cycle start-up: gas emitted directly to atmosphere, 72 events per year.

TABLE 4-15 CONTINUED

Reference No. (a)	5		6		7		8		9	
Stream Description	Steam Boiler Scrubbed Flue Gas		Incinerator Waste Gas From Stretford Plant & Steam Production		Waste Gas From Tar/Oil Distillation		Waste Gas From CO_2 Removal Incinerator		Waste Gas From Synthol Plant (d)	
	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h
HCN	0	0	0	0	0	0	0	0	0	0
SO_2	0.02	1,959	0.03	3,334	0	0	0	0	0	0
H_2S	0	0	0	0	0	0	0	0	0	0
COS	0	0	0	0	0	0	0	0	0	0
Org. Sulphur	0	0	0	0	0	0	0	0	0	0
CH_4	Trace	54	Trace	55	Trace	Trace	Trace	Trace	Trace	Trace
Hydrocarbons	0	0	0	0	0	0	0	0	0	0
CO	Trace	179	Trace	186	Trace	Trace	Trace	1	Trace	1
CO_2	11.96	853,990	21.13	1,831,855	15.28	3,198	56.33	79,201	15.28	15,993
NO_x	0.03	2,366	0.03	2,452	0.02	4	0.01	15	0.02	18
NH_3	0	0	0	0	0	0	0	0	0	0
O_2	4.19	217,501	3.70	233,775	3.03	462	1.35	1,380	3.03	2,308
N_2	69.03	3,134,376	62.54	3,340,691	69.06	9,198	30.06	26,900	69.06	45,990
H_2	0	0	0	0	0	0	0	0	0	0
H_2O	14.77	403,704	12.57	446,005	12.50	1,070	12.25	7,045	12.49	5,350
HCl	0	0	0	0	0	0	0	0	0	0
Cl_2	0	0	0	0	0	0	0	0	0	0
Argon	Trace	91	Trace	91	p.11	21	0	0	0.12	109
Particulates	N/A	105	N/A	110	N/A	Trace	N/A	1	N/A	1
TOTAL	100.00	4,614,335	100.00	5,968,554	100.00	13,955	100.00	114,552	100.00	69,764
Volume Flowrate (m^3/h @ STP)	3,597,172		4,421,523		10,644		71,556		53,246	
Emission Temperature (^oC)	55		88		-		-		-	

N/A - not applicable
d) - 87 days per year (it is not clear whether this is off-gas from catalyst regeneration)
- - no information available

TABLE 4-15 CONTINUED

Reference No.	10		11		12		13		14	
Stream Description	Waste Gas From Ethylene Plant		Waste Gas From Fuel Production		Regenerator Gas From Platformer		Regenerator Gas From C5/C6 + Isomerization (e)		Regenerator Gas From Naptha Hydrotreating (f)	
	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h
HCN	0	0	0	0	0	0	0	0	0	0
SO_2	0	0	0	0	0	0	0	0	0	0
H_2S	0	0	0	0	0	0	0	0	0	64
COS	0	0	0	0	0	0	0	0	0	0
Org. Sulphur	0	0	0	0	0	0	0	0	0	0
CH_4	Trace	Trace	Trace	Trace	0	0	0.1	9	0	0
Hydrocarbons	0	0	0	0	0	0	0	0	0	0
CO	Trace	1	Trace	3	0	0	0.3	46	0.15	44
CO_2	15.28	14,848	15.28	31,786	17.10	7	0.1	24	0.45	208
NO_x	0.02	16	0.02	35	0	0	0	0	0	0
NH_3	0	0	0	0	0	0	0	0	0	0
O_2	3.03	2,144	3.03	4,591	0.70	Trace	2.1	366	2.77	929
H_2	69.06	42,703	69.06	91.415	76.50	21	97.3	14,833	7.78	2,273
H_2	0	0	0	0	0	0	0.1	1	0	0
H_2O	12.50	4,967	12.50	10,633	5.50	1	0	0	88.67	16,656
HCl	0	0	0	0	0.10	Trace	0	0	0	0
Cl_2	0	0	0	0	0.10	Trace	0	0	0	0
Argon	0.11	98	0.11	211	0	0	0	0	0	0
Particulates	N/A	1	N/A	2	0	0	0	0	0	0
TOTAL	100.00	64,774	100.00	138,666	100.00	29	100.00	15,264	100.00	20,176
Volume Flowrate (m^3/h @ STP)	49,448		105,849		22		12,177		23,367	
Emission Temperature (^oC)	-		-		460		200-251		472	

e) - The specified emissions refer to 75% of the period (255 days of the year). During the remaining 25% of the regeneration period (85 days per year), the composition of the gas emitted to the atmosphere is: 98 Volume % N_2, 2 Volume % O_2.

f) - Emission takes place twice annually, for 30 hours in each case. During a further 8 hours, also twice annually, the gas emitted to the atmosphere consists of steam and air (total quantity is 17,800 m^3/h @ STP).

TABLE 4-15 CONTINUED

Reference No.	15			
Stream Description	Regenerator Gas From Heavy Oil Hydrotreating (g)		Total Emission Maximum (h)	Total Emission Average (i)
	Vol.%	kg/h		
HCN	0	0	0	0
SO_2	0	0	3,462	3,339
H_2S	0.12	11	144	8
COS	0	0	5	Trace
Org. Sulphur	0	0	5	Trace
CH_4	0	0	697	98
Hydrocarbons	0	0	82	5
CO	0.08	6	2,549	351
CO_2	0.24	28	1,987,702	1,965,202
NO_x	0	0	2,540	2,527
NH_3	0	0	52	0
O_2	1.74	150	246,104	243,165
N_2	97.82	7,376	3,705,301	3,642,776
H_2	0	0	325	19
H_2O	0	0	494,808	471,196
HCl	0	0	Trace	Trace
Cl_2	0	0	Trace	Trace
Argon	0	0	550	447
Particulates	0	0	153	152
TOTAL	100.00	7,571	6,444,481	6,329,286
Volume Flowrate (m^3/h @ STP)	6,029			
Emission Temperature (^oC)	510			

g) Emission occurs twice annually for 30 hours in each case. During an additional 6 hours, twice annually, emissions are 90 Vol.% N_2 and 10 Vol.% O_2.

h) The maximum theoretical value of momentary emission is based on assumption that all periodic emissions occur simultaneously.

i) The annual average of total emissions consists of emission rates for continuous plus periodic emissions.

TABLE 4-16

STORAGE TANK EMISSIONS FOR A SASOL-SYNTHOL PLANT (17)

Product	Throughput (m^3/d)	Tank Volume m^3	Overhead Vapour Mol. Wt. (kg/kg - mol)	Actual Overhead Vapour Press. (bar)	Type of Tank	Fixed Roof Losses (kg/d) Breathing	Operating	Total	Floating Roof (c) Losses (kg/d) Storage	Operating	Total
RAW PRODUCTS AND INTERIM STORAGE TANKS											
Light Oil	1,838	13,642	130	0.45	Floating Roof	N/A (d)	N/A	N/A	63.8	4.9	68.7
Light Oil	(a)	13,642	130	0.45	Floating Roof	N/A	N/A	N/A	63.8	(a)	63.8
Decant Oil	160	2,394	90	0.85	Dome Roof	0	0	0	N/A	N/A	N/A
Decant Oil	(a)	2,394	90	0.85	Dome Roof	0	0	0	N/A	N/A	N/A
Naptha (Hydrotreated)	890	3,670	105	0.19	Floating Roof	N/A	N/A	N/A	7.7	4.7	42.4
MIXED GASOLINE PRODUCTS STORAGE TANKS											
Gasoline	2,747	30,859	86	0.55	Floating Roof	N/A	N/A	N/A	85.3	5.4	90.7
Gasoline	(a)	30,859	86	0.55	Floating Roof	N/A	N/A	N/A	85.3	(a)	85.3
Gasoline	(a)	30,859	86	0.55	Floating Roof	N/A	N/A	N/A	85.3	(a)	85.3
DISTILLATE RESERVOIR FOR GASOLINE BY-PRODUCTS AND ADDITIVE TANKS											
Platformate	1,049	3,534	113	0.50	Floating Roof	N/A	N/A	N/A	23.2	5.6	28.8
Coal Naphtha	(a)	3,534	113	0.50	Floating Roof	N/A	N/A	N/A	23.2	(a)	23.2
Synthol	-	2,545	58	0.85	Spherical	0	0	0	N/A	N/A	N/A
C5-C6	-	2,545	58	0.85	Spherical	0	0	0	N/A	N/A	N/A
Desulphurized Polymerics	772	2,801	95	0.17	Floating Roof	N/A	N/A	N/A	0	4.0	4.0
(Jet Fuel)	(a)	2,801	95	0.17	Floating Roof	N/A	N/A	N/A	0	(a)	0
Gasoline Substitute C5	2,385	1,080	86	0.55	Floating Roof	N/A	N/A	N/A	9.7	20.6 (b)	30.3
Orange Colouring Agent	3	40	113	0.50	Floating Roof	N/A	N/A	N/A	2.6	0.1	2.7

N/A - Not Applicable

TABLE 4-16 - CONTINUED

Product	Throughput (m^3/d)	Tank Volume m^3	Overhead Vapour Mol. Wt. (kg/kg - mol)	Actual Overhead Vapour Press. (bar)	Type of Tank	Fixed Roof Losses (kg/d)			Floating Roof (c) Losses (kg/d)		
						Breathing	Operating	Total	Storage	Operating	Total
DISTILLATE RESERVOIR FOR RAW CHEMICAL PRODUCTS											
Acetone	91	95	58	0.55	Floating Roof	N/A	N/A	N/A	2.24	1.77	4.01
Acetone	(a)	95	58	0.55	Floating Roof	N/A	N/A	N/A	2.24	(a)	2.24
MEK	28	40	60	0.25	Floating Roof	N/A	N/A	N/A	0.64	0.68	1.32
MEK	(1)	40	60	0.25	Floating Roof	N/A	N/A	N/A	0.64	(a)	0.64
Methanol	6	40	32	0.35	Floating Roof	N/A	N/A	N/A	0.48	0.14	0.62
Methanol	(a)	40	32	0.35	Floating Roof	N/A	N/A	N/A	0.48	(a)	0.48
Ethanol	196	243	46	0.16	Floating Roof	N/A	N/A	N/A	0.68	3.08	3.76
Ethanol	(a)	243	46	0.16	Floating Roof	N/A	N/A	N/A	0.68	(a)	0.68
Propanol	55	79	60	0.01	Conical Roof	0.39	0.32	0.71	N/A	N/A	N/A
Propanol	(a)	79	60	0.01	Conical Roof	0.39	(a)	0.39	N/A	N/A	N/A
Butanol	29	40	24	0.04	Conical Roof	0.54	1.08	1.62	N/A	N/A	N/A
Butanol	(a)	40	74	0.04	Conical Roof	0.54	(a)	0.54	N/A	N/A	N/A
STORAGE TANKS FOR RAW CHEMICAL PRODUCTS											
Acetone	91	3,659	58	0.55	Floating Roof	N/A	N/A	N/A	13.61	0.52	14.13
MEK	26	1,024	60	0.25	Floating Roof	N/A	N/A	N/A	2.52	0.25	2.77
Ethanol	180	3,612	46	0.16	Floating Roof	N/A	N/A	N/A	3.04	1.03	4.07
Ethanol	(a)	3,612	46	0.16	Floating Roof	N/A	N/A	N/A	3.04	(a)	3.04
Propanol	51	2,162	60	0.07	Conical Roof	17.28	8.85	26.13	N/A	N/A	N/A
Butanol	27	1,091	74	0.04	Conical Roof	9.80	2.90	12.70	N/A	N/A	N/A
Methanol	20	1,805	32	0.35	Floating Roof	N/A	N/A	N/A	3.45	0.14	3.59
RESIDUE STORAGE FOR REPROCESSING											
Carbonyl (Tar)	176	378	55	0.55	Floating Roof	N/A	N/A	N/A	4.12	2.27	6.39
Alcohol	338	677	60	0.17	Floating Roof	N/A	N/A	N/A	1.90	3.64	5.54

TABLE 4-16 CONTINUED

Product	Throughput (m^3/d)	Tank Volume m^3	Overhead Vapour Mol. Wt. (kg/kg - mol)	Actual Overhead Vapour Press. (bar)	Type of Tank	Fixed Roof Losses (kg/d) Breathing	Fixed Roof Losses (kg/d) Operating	Fixed Roof Losses (kg/d) Total	Floating Roof (c) Losses (kg/d) Storage	Floating Roof (c) Losses (kg/d) Operating	Floating Roof (c) Losses (kg/d) Total
RAW PRODUCT AND INTERIM STORAGE TANKS											
Diesel 1-D	587	2,056	105	0.01	Conical Roof	6.7	8.0	14.7	N/A	N/A	N/A
Diesel 2-D	170	601	113	0.01	Conical Roof	3.3	2.5	4.8	N/A	N/A	N/A
Diesel Substitute	-	2,056	110	0.01	Conical Roof	7.0	8.0 (b)	15.0	N/A	N/A	N/A
Middle Distillate	556	1,948	95	0.14	Floating Roof	N/A	N/A	N/A	3.5	4.2	7.7
Jet Fuel	848	2,972	95	0.15	Floating Roof	N/A	N/A	N/A	5.8	4.6	10.4
Jet Fuel	(a)	2,972	95	0.15	Floating Roof	N/A	N/A	N/A	5.8	(a)	5.8
STORAGE TANKS FOR JET FUEL, DIESEL, HEATING OIL, VACUUM RESIDUE AND SUMP OIL											
Diesel 1-D	256	3,077	110	0.01	Conical Roof	9.7	7.7	17.7	N/A	N/A	N/A
Diesel 2-D	40	477	110	0.01	Conical Roof	2.4	1.3	3.7	N/A	N/A	N/A
Meadium Heating Oil	31	1,316	300	0.01	Conical Roof	13.3	2.7	16.0	N/A	N/A	N/A
Cleaned Waste Oil	16	159	105	0.55	Conical Roof	5.2	0	5.2	N/A	N/A	N/A
Vacuum Residue	39	159	350	<0.01	Conical Roof	1.3	C.4	1.7	N/A	N/A	N/A
Vacuum Residue	(a)	159	350	<0.01	Conical Roof	1.3	(a)	1.3	N/A	N/A	N/A
Jet Fuel	838	6,702	95	0.15	Floating Roof	N/A	N/A	N/A	9.0	3.5	12.5
Jet Fuel	(a)	6,702	95	0.15	Floating Roof	N/A	N/A	N/A	9.0	(a)	9.0
RAW PRODUCTS AND INTERIM STORAGE TANKS											
Coal Tar	420	192	78	0.25	Floating Roof	N/A	N/A	N.A	1.9	6.8	8.7
Carbonyl (Tar)	573	3,843	55	0.85	Dome Roof	0	0	0	N/A	N/A	N/A
Carbonyl (Tar)	148	3,843	55	0.85	Dome Roof	0	0	0	N/A	N/A	N/A
Alcohols	379	2,272	60	0.12	Floating Roof	N/A	N/A	N/A	2.9	2.5	5.4
Higher Alcohols	45	832	74	0.01	Conical Roof	3.6	0	3.6	N/A	N/A	N/A

TABLE 4-16 CONTINUED

Product	Throughput (m^3/d)	Tank Volume m^3	Overhead Vapour Mol. Wt. (kg/kg - mol)	Actual Overhead Vapour Press. (bar)	Type of Tank	Fixed Roof Losses (kg/d)			Floating Roof (c) Losses (kg/d)		
						Breathing	Operating	Total	Storage	Operating	Total
RAW PRODUCT AND INTERIM STORAGE TANKS											
Diesel 1-D	587	2,056	105	0.01	Conical Roof	6.7	8.0	14.7	N/A	N/A	N/A
Diesel 2-D	170	601	113	0.01	Conical Roof	3.3	2.5	4.8	N/A	N/A	N/A
Diesel Substitute	-	2,056	110	0.01	Conical Roof	7.0	8.0 (b)	15.0	N/A	N/A	N/A
Middle Distillate	556	1,948	95	0.14	Floating Roof	N/A	N/A	N/A	3.5	4.2	7.7
Jet Fuel	848	2,972	95	0.15	Floating Roof	N/A	N/A	N/A	5.8	4.6	10.4
Jet Fuel	(a)	2,972	95	0.15	Floating Roof	N/A	N/A	N/A	5.8	(a)	5.8
STORAGE TANKS FOR JET FUEL, DIESEL, HEATING OIL, VACUUM RESIDUE AND SUMP OIL											
Diesel 1-D	256	3,077	110	0.01	Conical Roof	9.7	7.7	17.7	N/A	N/A	N/A
Diesel 2-D	40	477	110	0.01	Conical Roof	2.4	1.3	3.7	N/A	N/A	N/A
Meadium Heating Oil	31	1,316	300	0.01	Conical Roof	13.3	2.7	16.0	N/A	N/A	N/A
Cleaned Waste Oil	16	159	105	0.55	Conical Roof	5.2	0	5.2	N/A	N/A	N/A
Vacuum Residue	39	159	350	<0.01	Conical Roof	1.3	0.4	1.7	N/A	N/A	N/A
Vacuum Residue	(a)	159	350	<0.01	Conical Roof	1.3	(a)	1.3	N/A	N/A	N/A
Jet Fuel	838	6,702	95	0.15	Floating Roof	N/A	N/A	N/A	9.0	3.5	12.5
Jet Fuel	(a)	6,702	95	0.15	Floating Roof	N/A	N/A	N/A	9.0	(a)	9.0
RAW PRODUCTS AND INTERIM STORAGE TANKS											
Coal Tar	420	192	78	0.25	Floating Roof	N/A	N/A	N.A	1.9	6.8	8.7
Carbonyl (Tar)	573	3,843	55	0.85	Dome Roof	0	0	0	N/A	N/A	N/A
Carbonyl (Tar)	148	3,843	55	0.85	Dome Roof	0	0	0	N/A	N/A	N/A
Alcohols	379	2,272	60	0.12	Floating Roof	N/A	N/A	N/A	2.9	2.5	5.4
Higher Alcohols	45	832	74	0.01	Conical Roof	3.6	0	3.6	N/A	N/A	N/A

TABLE 4-16 CONTINUED

Product	Throughput (m^3/d)	Tank Volume m^3	Overhead Vapour Mol. Wt. (kg/kg - mol)	Actual Overhead Vapour Press. (bar)	Type of Tank	Fixed Roof Losses (kg/d) Breathing	Fixed Roof Losses (kg/d) Operating	Fixed Roof Losses (kg/d) Total	Floating Roof (c) Losses (kg/d) Storage	Floating Roof (c) Losses (kg/d) Operating	Floating Roof (c) Losses (kg/d) Total
BY-PRODUCTS											
Coal Tar	447	4,244	275	0.01	Conical Roof	51.70	93.35	145.05	N/A	N/A	N/A
Coal Tar	(a)	4,244	275	0.01	Conical Roof	51.70	(a)	57.70	N/A	N/A	N/A
Rectesol Naphtha	115	1,651	85	0.29	Floating Roof	N/A	N/A	N/A	6.35	0.98	7.33
Rectesol Naphtha	(a)	1,651	85	0.29	Floating Roof	N/A	N/A	N/A	6.35	1.06	10.63
Coal Phenol	131	1,830	95	0.33	Floating Roof	N/A	N/A	N/A	9.57	1.06	10.63
INTERIM TANKS											
Light Naphtha	52	733	85	0.26	Floating Roof	N/A	N/A	N/A	3.53	0.58	4.11
Heavy Naphtha	109	1,528	130	0.08	Conical Roof	35.65	48.90	84.55	N/A	N/A	N/A
Medium Cresote	132	926	95	0.01	Conical Roof	5.13	7.12	12.25	N/A	N/A	N/A
Medium Cresote	(a)	926	95	0.01	Conical Roof	5.13	(a)	5.13	N/A	N/A	N/A
Heavy Cresote	98	687	120	0.01	Conical Roof	3.41	3.31	6.72	N/A	N/A	N/A
Heavy Cresote	(a)	687	120	0.01	Conical Roof	3.41	(a)	3.41	N/A	N/A	N/A
Residual Oil	124	867	150	< 0.01	Conical Roof	0.22	0.05	0.27	N/A	N/A	N/A
Residual Oil	(a)	867	150	< 0.01	Conical Roof	0.22	(a)	0.22	N/A	N/A	N/A
Heavy Distillate	375	1,311	150	< 0.01	Conical Roof	0.28	0.07	0.36	N/A	N/A	N/A
Heavy Distillate	(a)	1,311	150	< 0.01	Conical Roof	0.28	(a)	0.28	N/A	N/A	N/A
Deasphalting Oil	22	659	150	< 0.01	Conical Roof	0.18	0.01	0.19	N/A	N/A	N/A
Phenol	104	3,134	95	< 0.01	Conical Roof	13.47	5.72	19.19	N/A	N/A	N/A
STORAGE TANKS FOR MISCELLANEOUS PRODUCTS											
NaOH (25%)	-	320	23	0.04	Conical Roof	N/A	N/A	N/A	N/A	N/A	N/A
H_2SO_4 (98%)	-	159	98	< 0.01	Conical Roof	N/A	N/A	N/A	N/A	N/A	N/A

TABLE 4-16 CONTINUED

Product	Throughput (m^3/d)	Tank Volume m^3	Overhead Vapour Mol. Wt. (kg/kg - mol)	Actual Overhead Vapour Press. (bar)	Type of Tank	Fixed Roof Losses (kg/d) Breathing	Fixed Roof Losses (kg/d) Operating	Fixed Roof Losses (kg/d) Total	Floating Roof (c) Losses (kg/d) Storage	Floating Roof (c) Losses (kg/d) Operating	Floating Roof (c) Losses (kg/d) Total
SURGE TANKS AND TRANSPORT TANKS FOR LIGHT HYDROCARBONS											
Propane	-	1,574	44	6.20	Spherical	0	0	0	N/A	N/A	N/A
Ethane	-	781	30	10.80	Spherical	0	0	0	N/A	N/A	N/A
Propylene	-	344	42	18.26	Spherical	0	0	0	N/A	N/A	N/A
Butane	-	903	58	3.52	Spherical	0	0	0	N/A	N/A	N/A
AMMONIA STORAGE TANKS											
Ammonia	-	4,458	17	0.90	Dome Roof	N/A	N/A	N/A	N/A	N/A	N/A
Ammonia Products (specified by consumer)	-	245	17	0.90	Spherical	N/A	N/A	N/A	N/A	N/A	N/A
STORAGE TANKS FOR ISOPROPYL ETHER AND INDUSTRIAL CHEMICALS											
I.P.E. (Consumption Tanks)	4	30	98	0.37	Floating Roof	N/A	N/A	N/A	1.56	0.10	1.66
I.P.E. (Storage)	4	766	98	0.37	Floating Roof	N/A	N/A	N/A	5.81	0.04	5.85
I.P.E. (Storage)	(a)	766	98	0.37	Floating Roof	N/A	N/A	N/A	5.81	(a)	5.81
NaOH (50%)	-	1,770	29	0.01	-	N/A	N/A	N/A	N/A	N/A	N/A
H_2SO_4 (98%)	-	190	98	-	-	N/A	N/A	N/A	N/A	N/A	N/A
RAW PRODUCTS STORAGE											
Gasoline	4	40	86	0.55	Floating Roof	N/A	N/A	N/A	3.43	0.09	3.52
Diesel	4	40	105	0.01	Fixed Roof	0.31	0.09	0.40	N/A	N/A	N/A
Jet Fuel	4	40	95	0.15	Floating Roof	N/A	N/A	N/A	0.66	0.13	0.79
					TOTALS	298	271	569	579	100	679

NOTES

a) The product is channeled into one tank only at any given time. Thus only one tank is shown as operating.

b) Reserve tanks. Emissions occur only when the tanks are in use - a few times per year.

c) Emissions from floating roof tanks apply only to tanks with tight-fitting seals.

d) The total loss does not include periodic operation of the tank as indicated under (b).

TABLE 4-17 PARTICULATE EMISSIONS SUMMARY FOR A SASOL-SYNTHOL PLANT[17]

EMISSION SOURCE	EMISSION RATE (kg/h)
Stack Gas from Steam Generation and the Stretford Incinerator following FGD Treatment	106
Coal Grinding Plant	35[a]
Other Residual and Waste Gases	8
Coal Fines Transport to Steam Generation	2
Lime Storage and Transport	1[a]
Coal Storage	<0.5
Ash-Drying Off-Gas	<0.5
TOTAL	153

(a) maximum periodic emission

4.2.2. Ruhrkohle/Ruhrchemie Texaco-Mobil MTG Atmospheric Emissions

A comprehensive analysis of atmospheric emissions from an R/R Texaco Methanol Synthesis plant processing Illinois No. 6 coal has been prepared by Fluor GmbH[17]. Emissions from all plant sources, with the exception of storage tank emissions, are given based on a conceptual plant design employing emission control processes. While the analysis does not include emissions resulting from the further processing of methanol to gasoline products by the Mobil MTG process, atmospheric emissions from this process are not expected to be significant. Data from the evaluation of Sasol-Synthol plant storage tank emissions for methanol and gasoline products have been utilized in the present analysis. The summary of total atmospheric emissions for the given plant design basis is presented in Table 4-18. This includes storage tank emissions for methanol and gasoline based on one operating and three storage tanks for each product (see Table 4-16).

The conceptual plant design mass balance for the coal-to-methanol plant, including identification of atmospheric emission streams, is shown in Figure 4-8. The plant sulphur balance is presented in Figure 4-9.

The characteristics and flowrates on gaseous streams identified in Figure 4-8 are given in Table 4-19.

TABLE 4-18 ATMOSPHERIC EMISSIONS SUMMARY FOR AN R/R TEXACO-METHANOL SYNTHESIS PLANT[17]

Feed Coal	Illinois No. 6
Throughput[a] (tonne/day)	25,286
Sulphur Content (wt. %) (moisture and ash free basis)	3.48
Emissions: (kg/1,000 kg coal throughput)	
Sulphur Dioxide	3.06
Nitrogen Oxides	0.99
Carbon Monoxide	0.07
Carbon Dioxide	1,400
Particulates	0.09
Storage Tank Emissions[b] (kg/day)	360

a - Total for coal conversion and steam generation.

b - Based on four - 1805 m^3 live storage tanks for methanol and four - 30859 m^3 live storage tanks for gasoline.

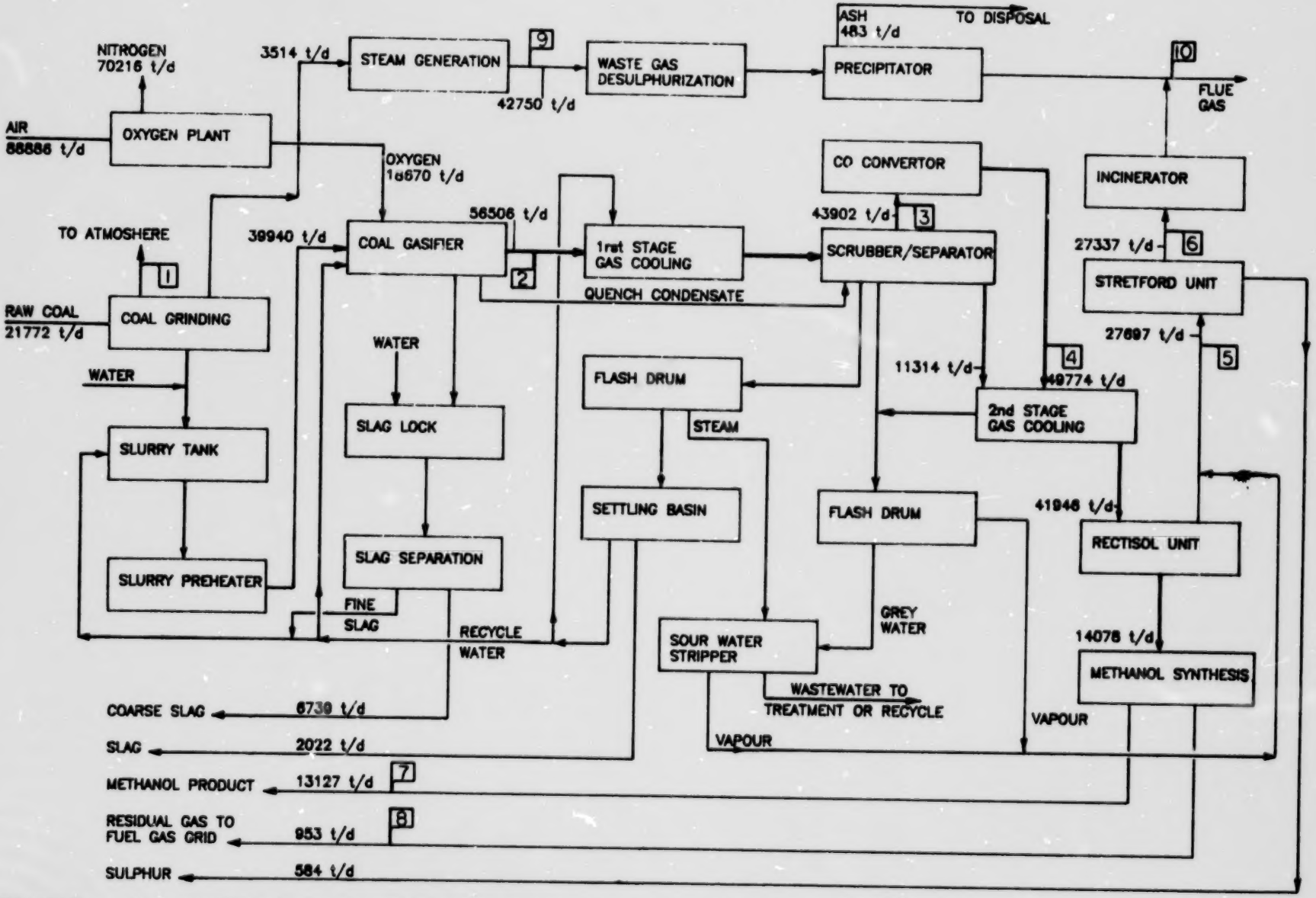
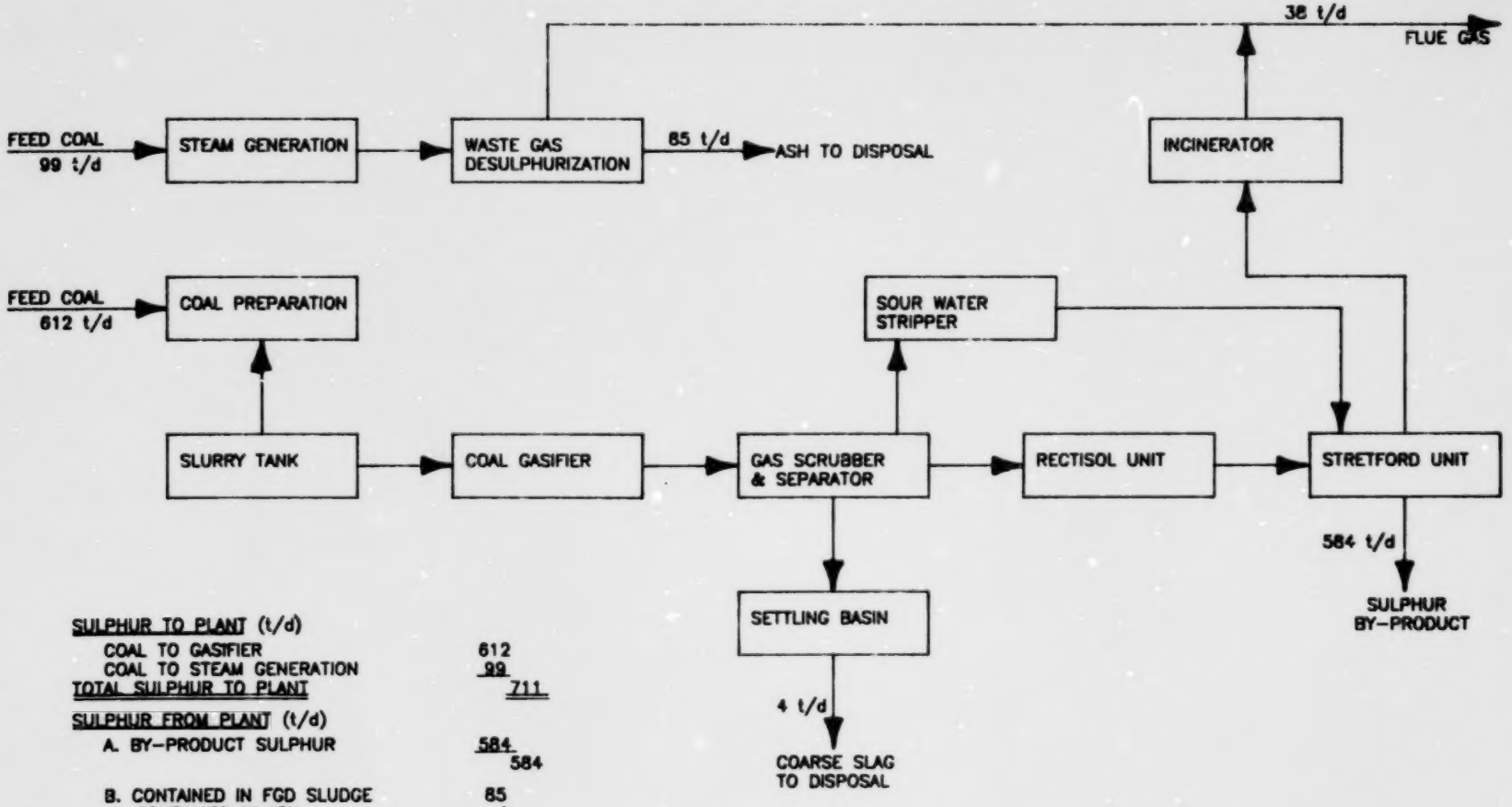


FIGURE 4-8 MATERIAL FLOW SCHEMATIC FOR THE R/R TEXACO GASIFICATION AND METHANOL SYNTHESIS PROCESSES (17)



SULPHUR TO PLANT (t/d)	
COAL TO GASIFIER	612
COAL TO STEAM GENERATION	99
TOTAL SULPHUR TO PLANT	711
SULPHUR FROM PLANT (t/d)	
A. BY-PRODUCT SULPHUR	584
	584
B. CONTAINED IN FGD SLUDGE	85
CONTAINED IN ASH	4
SUB-TOTAL	89
C. EMISSIONS TO ATMOSHERE (FLUE GAS FROM FGD UNIT AND STRETFORD INCINERATOR)	38
	38
TOTAL SULPHUR FROM PLANT	711

NOTE: Quantites in tonnes sulphur per calendar day.

FIGURE 4-9 SULPHUR BALANCE FOR R/R TEXACO GASIFICATION & METHANOL SYNTHESIS PROCESSES (17)

TABLE 4-19 CHARACTERISTICS OF GAS FLOWS AND ATMOSPHERIC EMISSIONS FROM R/R TEXACO - METHANOL SYNTHESIS PLANT (17)

Reference No. (a)	1*		2		3		4		5	
Stream Description	Waste Gas From Coal Grinding		Raw Gas From Gasifier		Raw Gas From Scrubber		Synthesis Gas From Co-Convertor		Waste Gas Feed To Stretford Unit From Rectisol And Stripper Units	
	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h
HCN	0	0	0	0	0	0	0	0	0.01	77
SO_2	0	0	0	0	0	0	0	0	0	0
H_2S	0	0	0.73	27,325	0.69	19,128	0.56	19,128	2.90	26,418
COS	0	0	0	0	0	0	0	0	0.06	907
Org. Sulphur	0	0	0	0	0	0	0	0	0	0
CH_4	0	0	0.13	2,271	0.12	1,607	0.10	1,607	0.53	2,271
C_2^+ Hydrocarbons	0	0	0	0	0	0	0	0	0	0
CO	0	0	25.06	771,462	22.20	540,831	5.76	162,243	0.34	2,598
CO_2	0	0	14.48	700,784	12.84	491,247	24.55	1,086,094	95.38	1,119,489
NO_x	0	0	0	0	0	0	0	0	0	0
NH_3	0	0	0	0	0	0	0	0	Trace	Trace
O_2	0	0	0	0	0	0	0	0	0	0
N_2	0	0	0.42	12,988	0.37	9,100	0.32	9,100	0.01	40
H_2	0	0	18.97	42,063	16.87	29,496	28.32	56,731	0.61	330
H_2O	0	0	39.98	790,936	46.71	730,949	40.35	730,866	0.25	1,201
HCl	0	0	0	0	0	0	0	0	Trace	Trace
Cl_2	0	0	0	0	0	0	0	0	0	0
Argon	0	0	0.23	9,916	0.20	6,909	0.17	6,909	Trace	23
CH_3OH	0	0	0	0	0	0	0	0	0	0
Particulates	N/A	33	0	0	0	0	0	0	0	0
TOTAL		33	100.00	2,357,745	100.00	1,829,267	100.00	2,072,678	100.00	1,153,354
Vol.Flowrate (m^3/h@STP)	N/A		2,461,016		1,947,385		2,252,165		597,741	

a) Flow references nos. are in accordance with material flow schematic: Figure 4-8
* Flows marked by asteriks are atmospheric emissions
N/A - Not applicable

TABLE 4-19 CONTINUED

Reference No. (a)	6		7		8		9		10*	
Stream Description	Residual Gas From Stretford Unit		Methanol Product		Residual Gas From Methanol Synthesis		Flue Gas From Steam Generation		Flue Gas From FGD & Stretford Incinerator	
	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h	Vol.%	kg/h
HCN	0.01	77	0	0	0	0	0	0	0	0
SO_2	0	0	0	0	0	0	0.22	8,227	0.05	3,223
H_2S	0.06	542	0	0	0	0	0	0	0	0
COS	0.06	907	0	0	0	0	0	0	0	0
Org. Sulphur	0	0	0	0	0	0	0	0	0	0
CH_4	0.55	2,271	0	0	8.49	2,032	Trace	Trace	Trace	22
C_2^+ Hydrocarbons	0	0	0	0	0	0	0	0	0	0
CO	0.35	2,598	0	0	27.49	12,292	Trace	73	0.01	76
CO_2	97.85	1,119,489	0.04	322	4.25	2,733	13.13	344,424	35.821	1,475,032
NO_x	0	0	0	0	0	0	0.04	1,007	0.02	1,039
NH_3	Trace	Trace	0	0	0	0	0	0	0	0
O_2	0	0	0	0	0	0	4.62	88,125	3.24	98,972
N_2	0.01	40	0	0	29.51	12,075	75.27	1,256,460	54.96	1,315,953
H_2	0.63	330	0.01	5	11.35	340	0	0	0	0
H_2O	0.48	2,255	12.64	41,142	0	0	6.72	72,159	5.90	82,806
Hcl	Trace	Trace	0	0	0	0	0	0	0	0
Cl_2	0	0	0	0	0	0	Trace	72	Trace	72
Argon	Trace	23	0	0	15.68	8,868	0	0	Trace	23
CH_3OH	0	0	87.31	505,462	2.78	1,331	0	0	0	0
Particulates	0	0	0	0	0	0	N/A	10,728	N/A	65
TOTAL	100.00	1,128,532	100.00	546,931	100.00		100.00	1,781,277	100.00	2,977,283
Vol.Flowrate (m^3/h@STP)	582,054		404,961		33,469		1,334,574		1,971,173	

4.2.3. H-Coal Atmospheric Emissions

As outlined in Section 4.1.3, the H-Coal Breckinridge Project Draft Environmental Impact Statement for the fully-integrated plant processing 21,389 tonne/d of ROM coal provided the basis for the H-Coal atmospheric emissions analysis[19]. U.S. EPA Best Available Control Technology (BACT) guidelines have beem employed in the selection of emission control processes for the plant. The overall material flow schematic for the plant is given in Figure 4-3, Section 4.1.3.

Table 4-20 shows the projected major emissions summary from principal sources in the plant. The sulphur dioxide emission rate for the plant is significantly lower than for either the Sasol-Synthol or Texaco-Mobil MTG full-scale plant processing very similar coals at comparable feed rates. Sulphur dioxide emission rates for the H-Coal plant are projected to be 0.68 kg/1,000 kg feed coal while the Sasol-Synthol and R/R Texaco-Mobil MTG plants are projected to emit 3.09 and 3.06 kg/1,000 kg feed coal respectively. This difference is due mainly to use of process-derived cleaned fuel gas in process heaters and the use of washed coal for steam generation and liquefaction in the H-Coal plant design. Information was, however, lacking with which to quantify the specific effects of coal washing and in-plant cleaned fuel gas use of overall atmospheric emission rates of sulphur dioxide and other major emissions such as nitrogen oxides and carbon monoxide.

Table 4-12 lists the selected control technologies to be employed in the Breckinridge Project for the major atmospheric pollutants from the plant including projected control efficiencies where available. The overall sulphur dioxide control scheme is shown diagramatically in Figure 4-10.

Projected emissions from the emergency flare systems for various plant modules are shown in Table 4-22.

TABLE 4-20 PROJECTED MAJOR EMISSIONS SUMMARY FOR THE H-COAL BRECKINRIDGE PROJECT (19)

(all values in kg/1000 kg feed coal throughput unless otherwise noted, 85 percent plant availability)

POLLUTANT	BOILER STACKS	PROCESS HEATERS	COAL HANDLING	CO_2 STRIPPER	PRODUCT STORAGE AND LOADING (including leakage)	TOTAL	TOTAL (kg/day)
Particulates	0.020	0.020	0.029	-	-	0.069	1,478
Sulphur Dioxide	0.59	0.07	0.02	-	-	0.68	14,506
Hydrogen Sulphide	-	-	0.0002	0.0011	-	0.00130	27.8
Carbonyl Sulphide	-	-	-	0.0068	-	0.0068	146.3
Sulphuric Acid Mist (H_2SO_4)	0.040	-	-	-	-	0.040	860.2
Nitrogen Oxide	0.39	0.14	0.04	-	-	0.57	12,242
Carbon Monoxide	0.036	0.037	0.012	0.080	-	0.158	3,577
Volatile Organics	0.011	0.016	-	-	0.103	0.129	2,763
Lead (tonne/yr)	0.00065	-	-	-	-	-	0.002
Beryllium (tonne/yr)	0.00065	-	-	-	-	-	0.002
Mercury (tonne/yr)	0.0008	-	-	-	-	-	0.003
Fluorides (tonne/yr)	0.062	-	-	-	-	-	0.20

TABLE 4-21 SUMMARY OF PROPOSED AIR POLLUTION CONTROLS FOR THE H-COAL BRECKINRIDGE PROJECT[19]

POLLUTANT	AREA	PREFERRED ALTERNATIVE	CONTROL EFFICIENCY (%)
SO_2	Boiler and Process	- Claus sulphur recovery with Claus tail gases combusted in boilers, SO_2 recycled through Claus units through Wellman-Lord. Produced gas for process heaters sweetened (amine).	Overall sulphur recovery 99.41 SO_2 removal (Wellman-Lord 92.38
NO_x	Boiler and Process	- Boiler design for NO_x reduction to meet regulations.	25 10
CO	Boiler and Process	- Minimal emissions from boilers, heaters, incinerators (no control). - Tankage controlled through floating roof and/or vapor recovery. - Fugitives controlled by use of low polluting process equipment with frequent inspection and maintenance to reduce leaks as required for Best Available Control Technology. - Loading facility with vapor recovery or flare.	N/A N/A
Total Suspended Particulates	Boilers	- Electrostatic precipitators	99.8
	Coal Handling	- Baghouses at heated and enclosed transfer points. - Covered conveyors. - Wet suppression at initial conveying point and stackers - Traveling, multilevel stackers. - Tunnel reclaim with baghouses. - Continuous bucket unloader. - Minimal drop distances. - Coal received (by barge) wet. - Belt speed optimization. - Bottom-dump rail cars. - Enclosed dumper house with baghouses. - Totally enclosed conveyors from onshore loading bin across roads and railroad tracks (baghouse at both ends).	99.8 90 90 80 99.8 90 90 99.8 99.8

TABLE 4-21 (cont'd)

SUMMARY OF PROPOSED AIR POLLUTION CONTROLS
FOR THE H-COAL BRECKINRIDGE PROJECT[19]

POLLUTANT	AREA	PREFERRED ALTERNATIVE	CONTROL EFFICIENCY (%)
	Coal Drying and Pulverizing	- Enclosed building with bag-houses and pneumatic conveying system.	99.8
	Ash Handling	- Pneumatic system with silo vent filters.	99.8
	Coal Storage	- Wet suppression for live piles.	80
		- Crusting agent for dead piles.	80
	Haul Roads	- Oiling and covered trucks where potential for fugitive emissions exists.	85
	Landfill	- Compacting and minimal exposed area with controlled reclamation	

N/A - Not Available

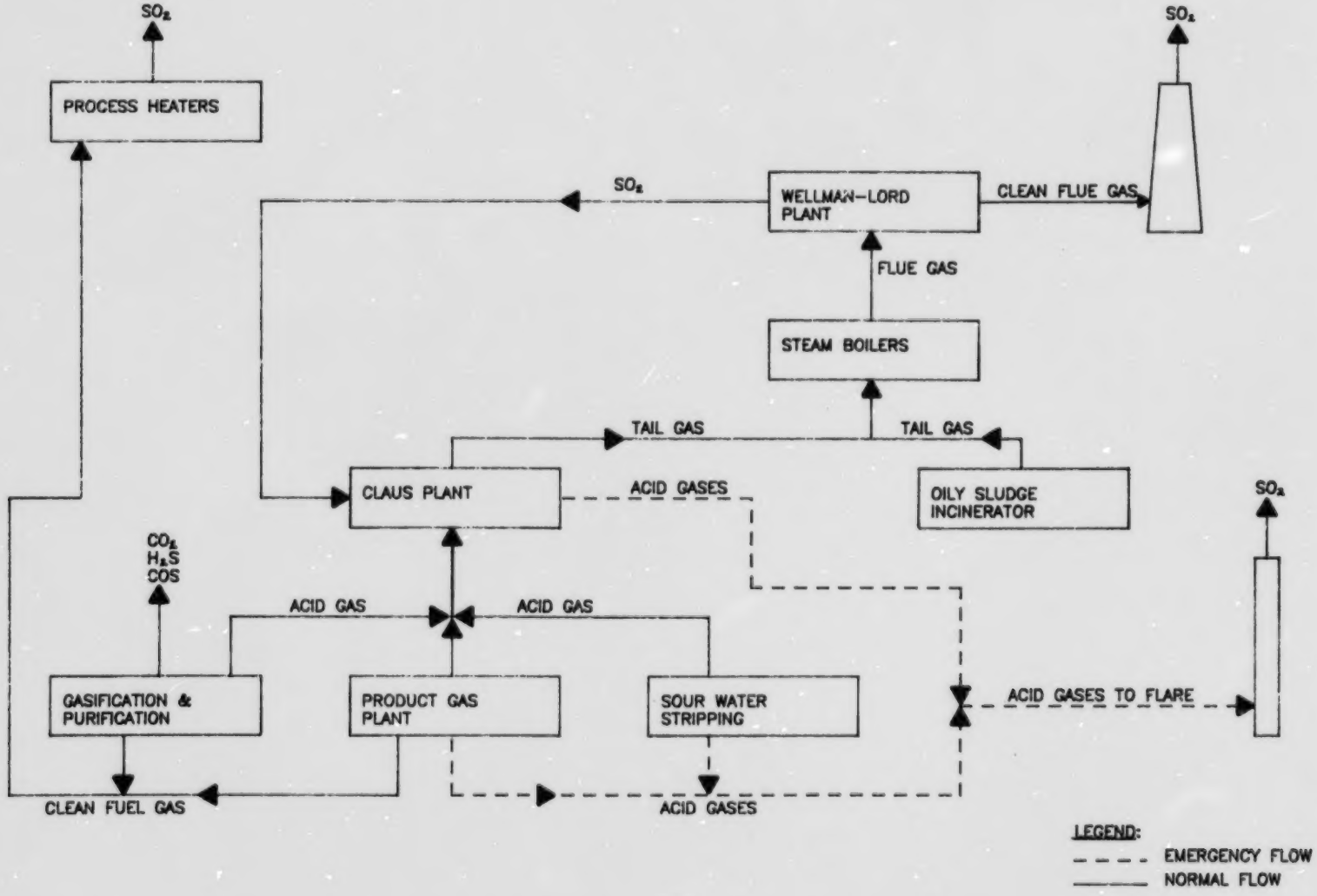


FIGURE 4-10 CONTROL SCHEME FOR SULPHUR DIOXIDE EMISSIONS FROM H-COAL BRECKINRIDGE PROJECT

TABLE 4-22

EMERGENCY FLARE SYSTEMS EMISSION SUMMARY FOR H-COAL BRECKINRIDGE PROJECT[19]

STREAM IDENTIFICATION	GASIFIER START-UP	PLANT EMERGENCY FLARE 42"0 x 360'H			H_2S EMERGENCY FLARE 6"0 x 150'H	SO_2 EMERGENCY FLARE 6"0 x 150"H
		FROM PLANT[a] 7	FROM PLANT 12	FROM PLANT 12	MIXED FEED TO CLAUS PLANT	ACID GAS FROM SCRUBBER
Gas volume to flares (m^3/min @ STP)	1,700	6,230	9,630	2,040	160	42
Maximum (kg/h)	79,240	696,530	449,690	96,990	13,915	6,408
Duration	½ Hour 1 Month	Unknown	Unknown	Unknown	Unknown	Unknown
Gas Composition Volume (%)						
CO	22.78	Refrigerant Grade Propane	22.79	51.07	.36	-
CO_2	3.18		3.18	7.6	18.22	-
H_2O	55.55		55.55	.002	12.71	8.38
C	.13		.13	.303	.024	-
H_2	17.64		17.64	40.5	.21	-
H_2S	.26		.26	.0003	67.38	-
COS	.0165		.016	.019	.019	-
AR & N_2	.223		.223	.50	.013	-
SO_2	-		-	-	-	91.62
Others	-		-	-	1.06	-

(a) - Plant reference No. from Figure 4-3, Section 4.1.3.

4.2.4. Lurgi Ruhrgas Pyrolysis/Power Generation Atmospheric Emissions

At present there is very little data available on projected atmospheric emissions from an L/R Pyrolysis/Power Generation facility. The majority of emissions are expected to originate from the steam boilers firing make-up coal and process-derived char and gas for electricity generation. Depending on the amount of product gas that is directed to the steam boilers (assumed in this case to undergo relatively minor clean-up) a range of approximately 60 to 95 percent of the original sulphur in the coal would appear in the boiler flue gas. Since the proposed feed coal for a Western Canada facility has a relatively low sulphur content, adoption of flue gas sulphur dioxide removal technology would likely depend entirely on implementation of more stringent regulations that those now proposed under the National Guidelines for New Stationary Sources, Thermal Power Generation Emissions[23]. In addition, firing of the char, which contains high ash levels, would likely necessitate burner modifications, thus affecting NO_x and CO emission rates relative to conventional coal firing.

Another potentially major emission from a fully-integrated plant will be hydrocarbon emissions from tar oil storage. The fugitive emission rate for coal tar generated by the Sasol-Synthol process, based on 447 m^3/d throughput to a 4,244 m^3 conical roof storage tank under loading/unloading conditions, is 145.05 kg/d of 275 average molecular weight organic species of unknown structure. Due to the high output of tars from the Lurgi Ruhrgas Pyrolysis process[24], and given that the tars are highly-aromatic in nature, storage tank emissions from this source may include significant levels of aromatic priority pollutants.

Information on the characteristics of emissions from heavy petroleum fractions is lacking in general.

Specific atmospheric emission streams from an L/R Pyrolysis Power Generation facility would include coal and char transfer and handling particulate emissions, coal pyrolysis reactor vent start-up gases and general fugitive emissions, acid gas/tail gas treatment process, flare exhaust gases, steam boiler flue gas, potential spent hydrotreater and alkylation catalyst off-gases, and product storage tank and loading fugitive emissions. More detailed information from conceptual plant design projects being carried out by Utah Power and Light for the Huntington Generation Station, Utah, and by the State Electricity Commission of Queenland, Australia, is due to become available in late 1983.

4.3. Wastewater Characteristics

4.3.1. Sasol-Synthol (Hat Creek) Aqueous Wastes

The overall water distribution schematic anticipated for a commercial plant in the Hat Creek Project prefeasibility design configuration is shown in Figure 4-11. Total water reuse for both the power generation and liquefaction facilities would be required with their implementation due to both environmental and fresh water availability concerns as outlined in the Environmental Impact Statement for a proposed 2,000 MW thermal electric power generation facility for Hat Creek[7]. This design concept required the use of the cooling towers as the end use of treated wastewaters.

Individual wastewater streams are identified as gasifier gas quench liquor, ash handling water blowdown, Rectisol still bottoms, chemical work-up aqueous fraction, hydrotreater aqueous fraction, cooling tower blowdown, plant sanitary sewage, ash disposal site runoff, coal pile runoff, and plant washdown and chemical cleaning wastes. The available data on the characteristics of these streams are documented below:

Gasifier Gas Liquor

Available information on the gas liquor stream relates to the aqueous phase after tar and oil separation. SASOL I data and data generated from the testing of U.S. coals at the Lurgi facility in Westfield, Scotland are presented in Table 4-23. Further data on phenolics composition in Lurgi (SASOL) gas liquor are given in Table 4-24. The performance of the Phenolsolvan and ammonia stripping pretreatment operations is documented in Tables 4-25 and 4-26. Finally, trace element data for the gas liquor before the above

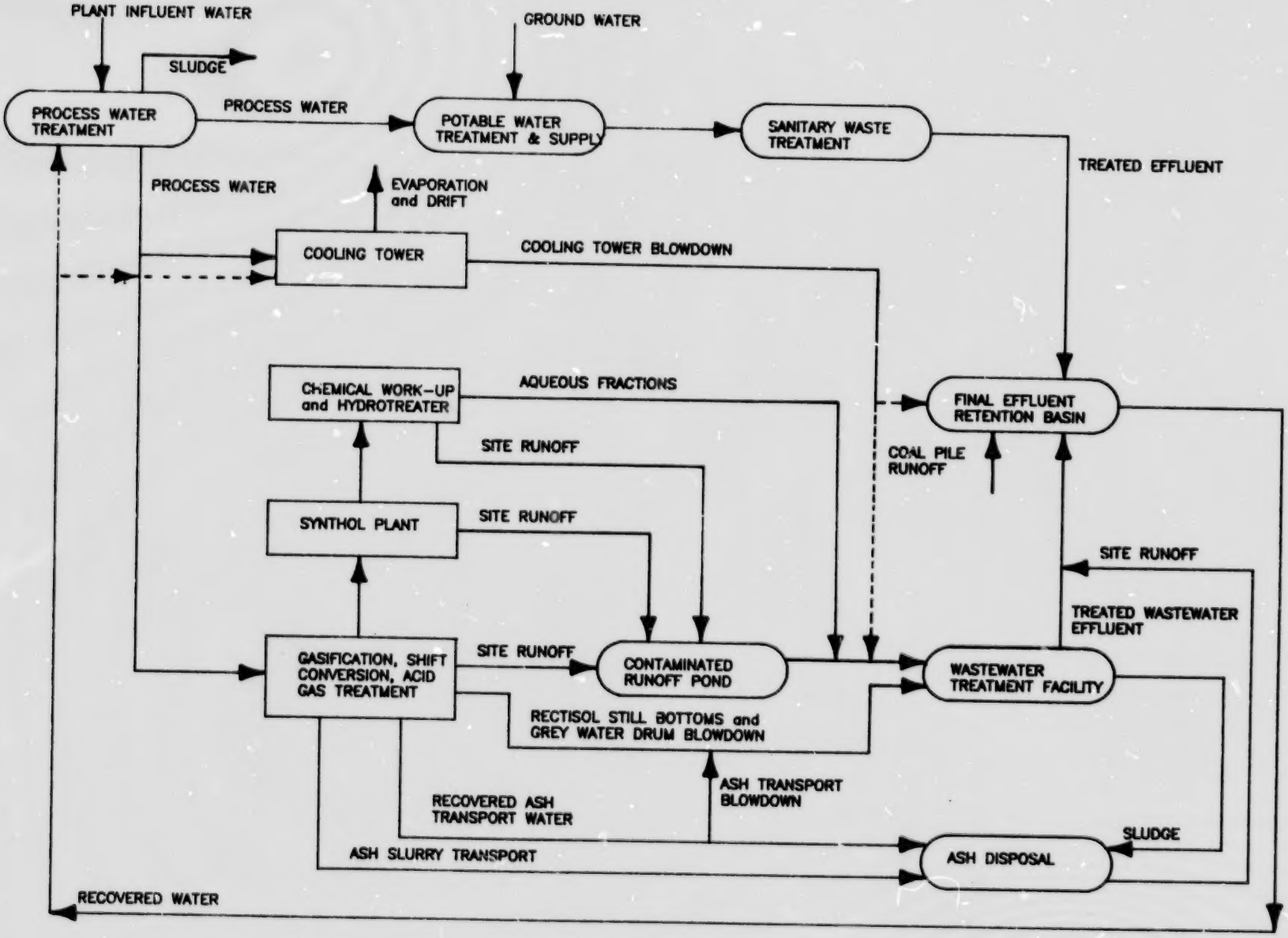


FIG. 4-11 WATER DISTRIBUTION SHEMATIC FOR A SASOL-SYNTHOL (HAT CREEK) PLANT

pretreatment from the processing of U.S. Western coals is given in Table 4-27 and the trace element balance for ash, gas liquor, and tar and oil by-product streams at SASOL I is presented in Table 4-28. The actual amount of trace element removal from gas liquor by the pretreatment operations and the levels of trace elements in the biological sludges produced downstream were not available.

Ash Handling Blowdown

The characteristics of the ash water will depend strongly on the nature of the make-up water used and whether it is process or internal reuse/recycle water. The best available data for predicting the leaching characteristics during quench and transport of Lurgi gasifier ash has been obtained from the testing of North Dakota lignite at SASOL I. Table 4-29 has been compiled based on the above laboratory testing where solubility estimates have been made for a number of ash elements. The data indicates that significant amounts of certain trace elements including boron, cesium, potassium, lithium, molybdenum, sodium, rubidium, sulphur, tungston, and zinc can be leached into the ash water assuming relatively high levels in the coal and the concentration factor in the ash. Furthermore, if an internal reuse/recycle water is used as make-up, organic substances which may be present may enhance metal solubility through the formation of organo-metallic complexes[25].

Rectisol Methanol/Water Still Bottoms

Regeneration of the methanol solvent in the Rectisol process by azeotropic distillation creates an aqueous waste stream. The amount of waste generated depends on the Rectisol design used. However, in a commercial-scale plant this flow is small compared to total wastewater flow and can be pumped directly to the treatment facility. Table 4-30 shows the

aqueous waste characteristics for the SASOL I plant employing the Rectisol type C process[8].

Chemical Work-Up Aqueous Fraction

The polar organic species synthesized in the Synthol reactor are directed to a separation plant where distillation ultimately generates an aqueous stream. The characteristics and flowrate of this wastewater stream were not available. It can be anticipated that this stream will contain mainly low-molecular weight alcohols and ketones based on the nature of the product fractions (See Figure 4-7).

Hydrotreater Aqueous Fraction

Heavier oxygenated and aromatic hydrocarbons are converted to naptha fractions by catalytic hydrogenation which generates aqueous and hydrogen sulphide wastestreams. The characteristics and flowrate of hydrotreater wastewater in the Sasol-Synthol process were not available.

Cooling Tower Blowdown

In the total water reuse mode of operation, the ultimate release of water from the plant would be evaporative losses from a cooling tower. The use of one or several recycle high-solids cooling towers will generate potentially significant high-solids blowdown streams. Data from SASOL II, currently operated in the zero-water discharge mode, were unavailable. Details of high-solids cooling tower operation, planned as the end use for recycled process wastewater for the H-Coal Breckinridge Project, were also unavailable. Recommended control limits for recirculating cooling water, presented in Table 4-31, can be used as an estimate of blowdown quality.

Plant Sanitary Sewage

Sanitary sewage from a commercial-scale plant will be directed to a separate package treatment unit. The effluent could be used for dust control and ash handling purposes to aid in minimizing overall plant fresh water requirements.

Ash Disposal Site Runoff

Lurgi gasifier ash and boiler bottom and fly ash from the power generation facility would likely be landfilled in a common disposal area for economic reasons. Preliminary estimates of leachate quality are the power generation plant combined bottom and fly ash are given in Table 4-32a.

The liquefaction plant will generate approximately double the ash produced by the power plant. The leachate characteristics of Lurgi gasifier ash after landfilling, were not available. Due to the intimate mixing of ash and transport water, data from Table 4-29 will not be representative of landfilled gasifier ash leachate quality.

Coal Pile Runoff

Hat Creek coal pile runoff projections presented in Table 4-32b, have been constructed from tests conducted during bulk coal sampling programs. Actual coal pile runoff patterns will be generally influenced by coal pile geometry, coal inventory, coal size, and climatic conditions.

Only one heavy metal species, magnesium, appears to be released at significant levels. Due to the already slightly alkaline pH and the nature and relatively low levels of the dissolved solids species compared to coal pile runoff from other Western coals, this stream could possible be combined with the cooling tower blowdown stream for a

coagulation/precipitation dissolved solids removal with lime or soda ash prior to discharge or reuse[26].

Plant Washdown and Chemical Cleaning Wastes

All washdown and chemical cleaning streams are, in general, directed to the contaminated site runoff equalization pond. The combination of dilution and quiescent conditions allows for oily wastes flotation and removal by skimming and initiates breakdown of complex chemicals such as organo-metal complexes. The pond effluent is ultimately fed to the wastewater treatment system.

The general water usage and wastewater treatment scheme currently used at SASOL II and III has been documented during a site visit by T.R. Bridle, Head of Residue Management Section, Wastewater Technology Centre, Burlington, Ontario. The summary report, detailing the process wastewater treatment train for total water reuse and the overall performance of the plant water treatment facilities, is presented in Appendix B.

TABLE 4- 23

CHARACTERISTICS OF LURGI GAS LIQUORS[8]

PARAMETER[a] \ COAL TYPE	MONTANA ROSEBUD SUB-BITUMINOUS	ILLINOIS NO. 6 BITUMINOUS	ILLINOIS NO. 5 BITUMINOUS	PITTSBURGH NO. 8 BITUMINOUS	SOUTH AFRICAN (SASOL I) SUB-BITUMINOUS	
Production Rate (kg/kg)	0.93	2.11	1.77	2.60	1.06	-
Susp. Tar & Oil	650	2150	2200	1100	5000	-
pH	9.6	9.8	9.5	9.3	-	8.9
TDS	4030	2770	3180	1550	-	2460
TDS after ignition	45	110	85	105	-	-
Sulphide	130	25	15	65	-	0.5
Total Sulphur	150	180	160	155	-	-
Fatty Acids	1250	490	400	275	300	-
Ammonia:						
Free	3990	1700	1520	1600	10600	11200
Fixed	395	280	410	320	150-200	-
Carbonate	4070	1280	680	1360	8500	-
Total Phenols	4200	2200	2900	1400	3250-4000	-
Monohydric Phenols	-	-	-	-	-	2410
Cyanide	2	3	7	1	6	-
Thiocyanate	6	65	79	70	-	85
Chloride	45	135	290	240	-	-
BOD	9900	3800	6000	4100	-	-
COD	2270	10100	9300	650	-	12500
TOD	-	-	-	-	-	4190

a = units in mg/l except for production rate and pH

TABLE 4-24 PERFORMANCE OF PHENOLSOLVAN/AMMONIA STRIPPING PRETREATMENT AT SASOL[8]

PARAMETER[a]	GAS LIQUOR AFTER TAR/OIL SEPARATION	GAS LIQUOR AFTER PRETREATMENT[b]	
Total Phenols	3250 - 4000	160	-
Steam Volatile Phenols	-	1	-
Fatty Acids (as CH_3COOH)	300	560	-
Total Suspended Solids	-	21	-
Total Dissolved Solids	-	875	596
Suspended Tar and Oil	5000	21	-
COD	-	1126	1330
Total Ammonia	10800	215	150
Total Sulphide	228	12	0.5
Cyanide	6	1	-
Thiocyanate	85	-	80
Fluoride	-	56	-
Chloride	-	25	-
Sodium	53	-	-
Calcium	-	18	-
Iron	-	1	-
Ortho-phosphate	-	2.5	0.2
Conductivity (umhos/cm)	-	1000 - 1800	-
pH	-	8.4	8.2

a = all units in mg/l except for pH and Conductivity.
b = data from individual sampling programmes.

TABLE 4-25 PHENOL COMPOSITION BREAKDOWN FOR RAW SASOL I LURGI GAS LIQUOR [8]

(VALUES IN mg/L)

Phenol Class/Compound	Tar Separator	Oil Separator
Total phenols	3570	5100
Monohydric phenols	1843	4560
Phenol	1260	3100
Cresols	483	1027
Xylenols	100	393
Catechols	1379	380
Resorcinols	348	240

TABLE 4- 26

CHARACTERISTICS OF RAW AND PROCESSED WASTEWATER FROM THE LURGI DRY ASH PROCESS PLANT AT SALSOLBURG, SOUTH AFRICA (8)

General Properties

Parameter	Values	
	[d] Raw Wastewater	Processed Wastewater[e]
Phenol, mg/l	1,250	3.2
Chemical oxygen demand, mg/l	12,500	1,330
Organic carbon, mg/l	4,190	[a]
Total dissolved solids, mg/l	2,460	596
pH	8.9	8.9
Ammonia, mg/l	11,200	150

Concentration of Specific Compounds

Compound	Concentration (mg/l)[b]	
	Raw Wastewater	Processed Wastewater
Fatty Acids		
Acetic acid	171	123
Propanoic acid	26	30
Butanoic acid	13	16
2-Methylpropanoic acid	2	5
Pentanoic acid	12	7
3-Methylbutanoic acid	1	5
Hexanoic acid	1	8
Monohydric Phenols		
Phenol	1,250	3.2
2-Methylphenol	340	0.2
3-Methylphenol	360	0.2
4-Methylphenol	290	0.2
2,4-Dimethylphenol	120	[c]
3,5-Dimethylphenol	50	[c]
Aromatic Amines		
Pyridine	117	0.42
2-Methylpyridine	70	0.05
3-Methylpyridine	26	0.05
4-Methylpyridine	6	0.05
2,4-Dimethylpyridine	1	[c]
2,5-Dimethylpyridine	1	[c]
2,6-Dimethylpyridine	1	[c]
Aniline	1	[c]

a. Not determined.

b. Data obtained from single samples. Raw wastewater samples were less than 6 months old, and treated wastewater samples were less than 1 month old.

c. Not found.

d. Raw wastewater: after tar/oil separation.

e. Processed wastewater: Phenolsolvan and ammonia stripping.

TABLE 4-27 TRACE ELEMENTS IN LURGI GAS LIQUOR AFTER TAR/OIL SEPARATION (U.S. COALS)[8]

[a] PARAMETER \ COAL TYPE/ORIGIN	Subbituminous Rosebud Montana	Lignite N. Dakota	Lignite N. Dakota
Liquor Production Rate (kg/kg) dry basis	0.93	1.53	1.53
Al	-	2.9	-
Ca	-	14.6	-
Fe	-	0.2	-
K	-	0.8	-
Na	-	82.5	-
Si	-	117	-
Ti	-	0.02	-
Mg	-	0.6	-
Ag	0.017	-	0.2
As	0.014	0.1	3
B	5.3	0.9	3
Ba	0.001	0.005	-
Be	0.22	-	0.008
Br	-	0.001	-
Cd	0.1	0.2	0.03
Ce	-	0.006	-
Co	0.001	0.001	0.03
Cr	1.3	0.02	0.03
Cu	1	0.02	0.3
F	19	5	0.5
Hg	0.056	0.17	0.003
Li	0.9	0.002	0.02
Mo	0.01	0.04	0.2
Mn	0.91	0.03	-
Ni	0.5	0.006	0.2
P	-	6	-
Pb	0.12	0.005	0.2
Rb	-	0.003	-
Sb	0.002	-	0.03
Sc	-	0.006	-
Se	0.05	0.004	2
Sn	0.45	-	0.03
Sr	-	0.004	-
U	0.15	-	0.2
V	2.5	0.001	0.003
Y	-	0.004	-
Zn	0.06	0.2	0.4
Zr	-	0.008	-

a - All units in mg/L unless otherwise indicated.

TABLE 4-28 TRACE ELEMENT BALANCE FOR LURGI AT SASOL* (12)

(% OF ELEMENT IN COAL)

Element	Ash	Liquor	Tar	Oil	Total
Be	1	1.6	0.5	0.01	3
B	36	3.5	0.8	0.002	40
V	72	0.06	0.005	0.001	72
Mn	154	0.36	0.005	<0.001	154
Ni	154	0.64	0.05	<0.01	155
As	36	90	2.5	5.2	134
Cd	40	35	0.5	1.1	77
Sb	40	36	3	0.5	80
Ce	72	0.1	0.003	0.001	72
Hg	40	32	4.9	0.5	77
Pb	180	3.2	8.2	0.02	191
Br	3.6	32	0.05	-	36
F	54†	42†	0.08	0.003	96
Cl	51†	46†	0.24	0.008	97

* Analysis by spark source mass spectrometer (which can give a semi-quantitative analysis) for El Paso Natural Gas Co. by SASOL.

†% distribution calculated on analyses as done by SASOL previously.

TABLE 4-29

ESTIMATED SOLUBILITY OF ELEMENTS IN LURGI ASH FROM GASIFICATION OF DUNN COUNTY, NORTH DAKOTA LIGNITE (8)

Element	Percent of Element Leachable*	Quantity of Element Solubilized,* kg/tonne (lbs/ton) of Ash	Estimated Maximum Concentration of Elements in Ash Slurry Supernatant† (mg/l)
Al	0.32	0.15 (0.29)	87
As	0.74	0.0005 (0.001)	0.3
B	15.9	0.0015 (0.003)	41
Ba	<0.09	<0.0001 (<0.003)	0.8
Br	13	0.0015 (0.003)	0.9
Ca	0.49	0.53 (1.06)	321
Co	1.6	0.0005 (0.001)	0.3
Cr	4.4	0.02 (0.04)	11
Cs	42	0.005 (0.001)	0.4
Cu	7	0.01 (0.02	6
F	4.5	0.005 (0.01)	2.6
Ga	5.4	0.0015 (0.003)	1
Ge	<1.3	<0.0005 (<0.001)	0.03
Fe	<0.4	<0.2 (<0.4)	<100
Hg	4.4	<0.0005 (<0.001)	<0.0001
K	21	0.7 (1.3)	395
Li	11	0.001 (0.002)	0.6
Mn	<0.25	<0.005 (<0.01)	<3
Mo	92	0.11 (0.23)	71
Ni	1.4	0.001 (0.002)	6
Na	37.1	5.9 (11.7)	3500
P	<0.5	<0.005 (<0.01)	<3
Pb	0.31	<0.0005 (<0.001)	0.06
Rb	59	0.015 (0.03)	10
S	84	8.7 (17.3)	5231
Sc	<0.66	<0.0005 (<0.001)	<0.2
Se	<34	<0.0005 (<0.001)	<0.17
Sr	0.71	<0.05 (0.1)	30
Ti	<2.3	<0.05 (<0.1)	<25
W	24	<0.001 (<0.002)	<0.6
V	5.2	<0.001 (0.002)	4.7
Zn	37	0.002 (0.004)	1.2

*Estimated for Dunn County lignite ash based on data for Mercer County lignite gasified in Lurgi gasifier at SASOL, South Africa.

†Assuming that ash slurry contains 0.6 kg ash/kg water.

TABLE 4-30 CHARACTERISTICS OF RECTISOL METHANOL/WATER STILL BOTTOMS FOR LURGI FACILITY AT SASOL, SOUTH AFRICA[8]

Stream Flow Rate liters 10^3 m^3 of feed gas (STP) (gal/1000 scf)	42 (0.31)
pH	9.7
Phenol (mg/L)	18
CN^- and SCN^- (mg/L)	10.4
NH_3 (mg/L)	42
$S^=$ (mg/L)	Trace
COD (mg/L)	1606
Conductivity (μmhos/cm)	1111

TABLE 4-31 CONTROL LIMITS FOR COOLING TOWER CIRCULATING WATER COMPOSITION (27)

PARAMETER	CONVENTIONAL AT LOW pH	SUGGESTED AT HIGH pH WITH HIGH CYCLE CONC. WITH DISPERSANTS
pH	6.5 to 7.5 ± 0.5	7.5 to 8.5 ± 0.3
Suspended Solids, mg/L	200 - 400	300 - 400
Carbonates, CO_3 mg/L	5	5
Bicarbonates, HCO_3 mg/L	50 - 150	300 - 400
Silica, SiO_2 mg/L	150	150 - 200
Mg x SiO_2 * mg/L	35,000	60,000**
Ca X SO_4 * (all as $CaCO_3$) mg/L	1,500,000 to 2,500,000	2,500,000 to 8,000,000 **
Ca X CO_3 * (all as $CaCO_3$) mg/L	1,200	6,000 **
Ca X mg X $(CO_3)^2$ mg/L	-	2,000,000 to 4,000,000
Chlorides, Cl	No Limit ***	No Limit ***
COD, BOD, NH_3	LIMIT DETN. BY TYPE OF BIOCIDE USED	

* Solubility Product e.g. (Mg mg/L) x (SiO_2 mg/L)

** More data needed to confirm.

*** For stainless steel in the cooling system, chlorides must be below 3,000 mg/L

TABLE 4-32a PRELIMINARY ESTIMATES OF COMBINED ASH LEACHATE QUALITY* (5)

PARAMETER (mg/L)	RANGE
pH (units)	8.0 - 9.0
Filterable Residue (105°C)	4800 - 8900
BOD_5	35 - 195
Alkalinity (as $CaCO_3$)	1120 - 1260
Chloride	175 - 190
Fluoride	3.3 - 4.9
Nitrate	2.4 - 3.3
Ortho-phosphate (as P)	0.14 - 0.31
Sulphate	1500 - 1580
Arsenic	0.16 - 2.4
Boron	3.0 - 3.6
Cadmium	0.10
Calcium	1050 - 1130
Chromium	0.12 - 0.20
Copper	0.23 - 0.33
Iron	1.95 - 2.05
Lead	0.05
Magnesium	220 - 230
Mercury	0.0013 - 0.0023
Sodium	325 - 335
Vanadium	0.18 - 0.22
Zinc	0.82 - 2.5

* Based on Fly Ash to Bottom Ash ratio of 75/25, conditioned and wetted with recycled powerplant wastewaters to 20% and 40% moisture respectively. These estimates need further study for verification.

TABLE 4-32b PROJECTED LOW GRADE COAL AND COAL LEACHATE CHARACTERISTICS[5]

PARAMETERS (mg/L)	LOW GRADE COAL*	COAL **
pH (units)	4.6	5.0
Filterable Residue (105°C)	5400	8400
BOD_5	N.D.	N.D.
Alkalinity (as $CaCO_3$)	0.5	27
Chloride	0.88	14
Fluoride	N.D.	0.10
Nitrate - N	N.D.	N.D.
Ortho-phosphate -P	N.D.	0.01
Sulphate	3800	3700
Arsenic	0.005	0.005
Boron	0.07	0.31
Cadmium	N.D.	N.D.
Calcium	1075	1900
Chromium	0.010	0.01
Copper	0.007	0.04
Iron	0.01	0.26
Lead	N.D.	N.D.
Magnesium	1680	2240
Mercury	0.0003	0.0003
Sodium	150	190
Vanadium	0.006	0.04
Zinc	0.18	0.11

N.D. - Not Determined

* - Based on one sampling of leachate collected from storage pile constructed as part of the bulk sample programme. Data supplied by B.C. Hydro. Sampling data 28/4/78.

** - Based on three (3) samplings of leachate collected from coal storage pile constructed as part of the bulk sample programme. Raw sata supplied by B.C. Hydro.

4.3.2. R/R Texaco-Mobil MTG Aqueous Wastes

As outlined in Section 4.1.2., environmental data from the German pilot-plant is currently unavailable. However, the overall performance of both the German and U.S. (Montebello) pilot units have been shown to be comparable (see Table 4-6). The major dissimilarity between designs is that the German unit employs waste heat recovery from the raw gas before water quenching. In terms of wastewater characteristics, the quench at lower temperature results in fewer carboxylic acids being formed while other characteristics remain essentially the same[18]. Therefore, information from the Montebello pilot unit is considered in this section as potentially worst-case data for the R/R Texaco process.

The overall water distribution schematic for a conceptual plant located on Cape Breton Island is shown in Figure 4-12. The schematic depicts several potential modes of utilizing water - once-through with treatment and discharge, reuse of treated wastewater in the process section, or final treated wastewater use as plant cooling water in a cooling tower. Individual wastewater streams are identified as gasifier gas quench liquor blowdown (grey water blowdown), slag handling water blowdown, methanol synthesis aqueous fraction, Mobil-M gasoline synthesis aqueous fraction, Rectisol still bottoms, demineralizer regenerant wastewater (from waste heat recovery boiler feedwater treatment), plant sanitary sewage, slag disposal runoff, coal pile runoff, and plant washdown and chemical cleaning wastes. The available data on the characteristics of these streams is documented below.

Gas Quench Liquor and Slag Water Blowdown

The characteristics of these streams are given in Table 4-33 for the processing of Illinois No. 6 and Western U.S.

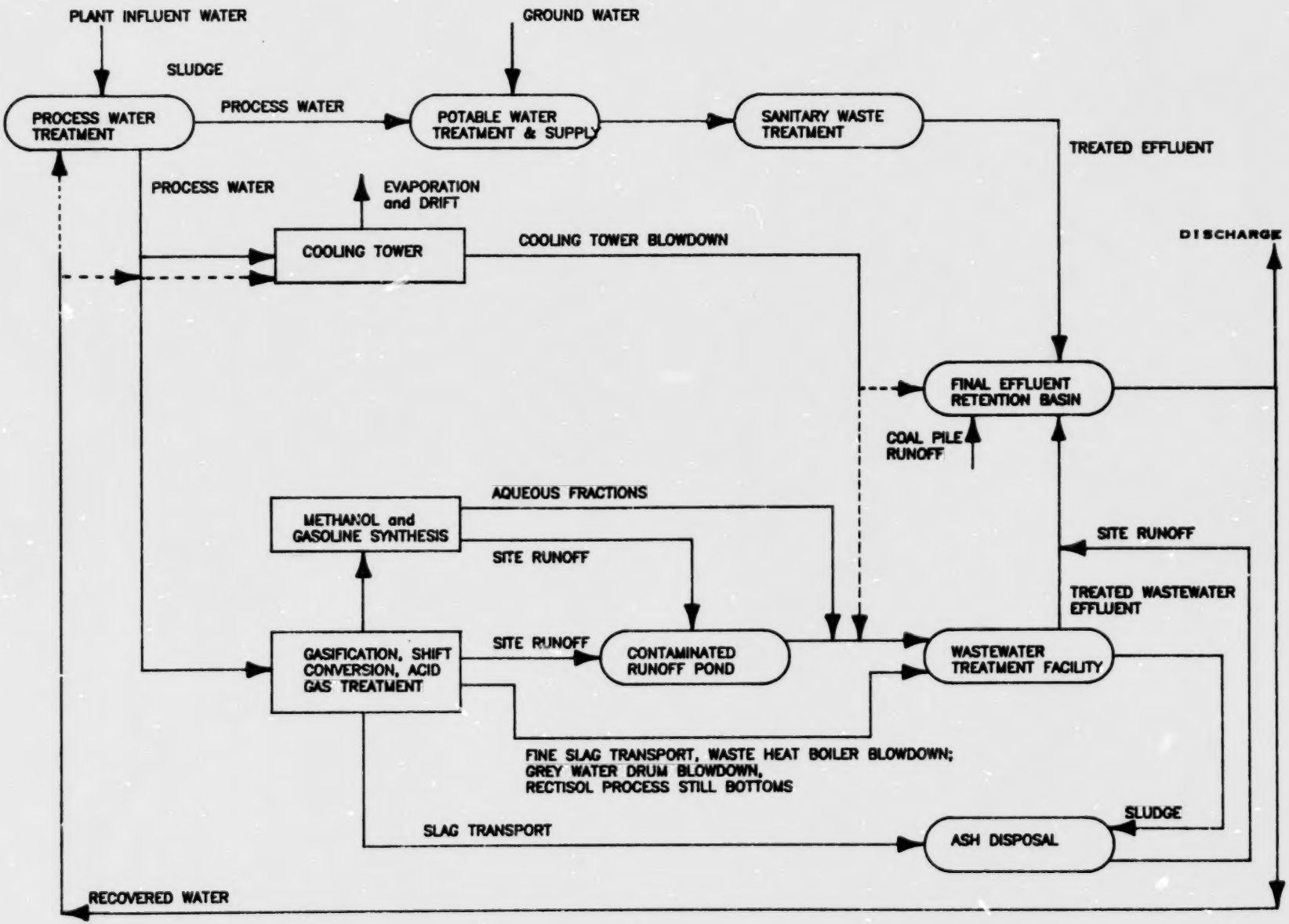


FIG. 4-12 WATER DISTRIBUTION SCHEMATIC FOR AN R/R TEXACO-MOBIL MTG PLANT

Kaiparowits low-sulphur bituminous coal at the Montebello pilot plant. The fresh process water make-up quality is included with these data. In normal operation, the recycle rates of these streams are designed to produce a blowdown with 2,500 ppm total dissolved solids[18].

Methanol Synthesis Aqueous Fraction

Crude methanol from the synthesis unit undergoes distillation to remove water and gaseous by-products resulting in an aqueous waste stream. In a conceptual design by Davy Powergas for Winkler gasification coupled to ICI Methanol synthesis, the crude methanol contains 6.28 percent by weight of water of which 5.58 percent is rejected as aqueous waste from the still[28]. The wastewater contains trace amounts of methanol, dimethyl ether, methyl formate, ethanol and higher alcohols. The actual production and composition of this stream will depend mainly on the Methanol synthesis process selected. However, in all cases the flowrate will be relatively small compared with the total plant aqueous waste fraction[29].

Mobil-M Gasoline Synthesis Aqueous Fraction

The catalytic conversion of methanol to an aliphatic hydrocarbon gasoline fraction entails the removal of oxygen from methanol as water with simultaneous carbon-chain forming reactions. A simple mass balance for Mobil-M gasoline synthesis and the composition of the aqueous waste stream generated from a 4 bbl/d pilot-plant is shown in Table 4-34. Note that 56 wt. % of the feed methanol to the plant is rejected as the aqueous fraction. However, the pilot plant data appears to indicate that it will contain only low molecular weight, readily biodegradable organics. More detailed information from a full-scale system will be required to verify these predictions.

Rectisol Methanol/Water Still Bottoms

In the Rectisol acid gas treatment process the methanol solvent is regenerated to release an aqueous waste stream. The only data available on this stream are for the SASOL I plant which is given in Table 4-30. Due to the difference in nature between Lurgi and Texaco gasifier quench liquor in terms of organics, the Rectisol still bottoms from an R/R Texaco plant should not contain phenolic or substantially large amounts of carboxylic acid compounds.

Demineralizer Regenerant Wastewater

The composition and frequency of periodic wastewater generation from demineralizers are dependent on the raw water quality after process water treatment and therefore are difficult to predict. Total dissolved solids, mainly $CaCl_2$ and NaCl, can be as high as 100,000 ppm for coal-fired power plant waste[30]. Following neutralization, this stream generally is impounded and discharged. However, because the Texaco gas liquor requires a chemical precipitation pretreatment, the option exists to blend this stream into the pretreatment process.

Plant Sanitary Sewage

In a large-scale commercial plant, sanitary sewage will be treated separately in a package activated sludge unit. The effluent from the plant may be discharged or recycled to raw process water treatment where fresh water availability is low.

Slag Disposal Runoff

Due to the ash content of the coal, a very large amount of coarse slag will be generated over the life of the plant and

discharged to land disposal. Process water and wastewater treatment sludges are likely to be co-disposed on the slag site as well for economic reasons. As there were no data available on wastewater sludge leachability, only the data on slag leachate can be given. This information, generated in laboratory simultation studies, is presented in Table 4-35 for slag generated at the Montebello pilot unit. Some caution must be exercised in the interpretation of this data since rainfall in Eastern Canada has a relatively low pH and may leach higher levels of trace metals when in contact with the slag.

Coal Pile Runoff

Table 4-36 presents an analysis of coal pile runoff for unwashed Sydney coal at the Cape Breton Lingan Generating Station. The data can be interpreted as a potentially worse case analysis since coal fed to a commercial liquefaction plant in Cape Breton would very likely undergo coal washing at the centralized Victoria Junction coal washing facility before shipment to and storage at the plant site. A very large inventory of washed coal would be required for a commercial-scale plant for protection against strikes, bad weather, or other disruption to delivery.

Plant Washdown and Chemical Cleaning

Similar wastes generated at petroleum refineries are directed to the contaminated runoff pond for oil separation and dilution to initiate breakdown of complex chemical wastes such as organo-metal compounds. The combined waste is ultimately fed to the process wastewater treatment system.

TABLE 4-33

TEXACO GASIFIER WASTEWATER QUALITY[18]

PARAMETER	ILLINOIS NO. 6 COAL			KAIPAROWITS COAL[a]		
	MAKE-UP SLAG QUENCH WATER	SLAG WATER BLOWDOWN	GAS LIQUOR BLOWDOWN	MAKE-UP SLAG QUENCH WATER	SLAG WATER BLOWDOWN	GAS LIQUOR BLOWDOWN
pH	NR[b]	8.0	7.7	5.3	8.9	8.8
TDS, ppm	0.0	355	1708	<5	28	420
Conductivity	NR	1650	7100	<10	410	10800
COD, ppm	NR	221	405	<5	48	760
TOC, ppm	<1	28	215	0.4	38	360
Ammonia, ppm	NR	380	1270	<1	130	2700
ANIONS, ppm						
Bromide	<1	<1	<1	<0.05	<0.05	0.05
Chloride	29	146	740	0.1	42	7.5
Fluoride	<1	31	175	<0.01	<0.01	28
Cyanide	NR	1	8	0.2	0.4	11
Formate	<1	94	522	0.1	56	1200
Nitrate	<1	3	9	<0.5	<0.5	2.0
Sulphide	0.3	6	316	<0.5	<0.5	61
Sulphate	25	38	21	1.3	5	47
Thiocyanate	NR	2	8	<4	<4	29
Thiosulphate	NR	5	NR	-	-	-
TRACE ORGANICS, ppb						
Benzene	-	<0.5	3.0	-	-	-
Toluene	-	<0.5	2.0	-	-	-
Anthracene	-	1.0	0.5	-	-	-
Flouranthene	-	2.0	0.5	-	-	-
Napthalene	-	-	2.0	-	-	-
Pyrene	-	0.6	0 7	-	-	-
Phenanthrene	-	0.2	0.02	-	-	-
Phenols	-	NR	<10	NR	1.2	1.2
Unidentified	-	-	-	NR	7.0	2.8
TRACE ELEMENTS, ppm						
Antimony	<0.001	0.016	<0.001	<0.001	<0.001	<0.001
Arsenic	0.002	0.07	0.022	<0.001	0.015	0.016
Barium	0.03	0.10	0.54	0.004	0.05	0.90
Beryllium	0.0004	0.005	0.018	<0.001	<0.001	0.002
Boron	-	-	-	0.2	0.3	1.4
Cadmium	0.010	0.003	0.003	<0.006	<0.001	<0.001
Chromium	0.002	0.003	0.006	<0.001	<0.001	<0.001
Cobalt	0.005	0.10	0.021	<0.001	<0.001	<0.001
Copper	0.01	0.017	0.010	0.031	0.008	0.005
Flourine	<1	31	175	<0.1	<0.01	29
Lead	0.005	0.045	0.054	<0.005	0.011	<0.005
Manganese	0.13	0.08	0.104	0.002	0.003	0.024
Mercury	<0.0001	<0.0001	<0.0001	0.002	0.002	0.002
Molybdenum	<0.02	0.03	<0.02	<0.001	0.003	0.015
Nickel	0.03	0.07	0.03	<0.01	<0.01	<0.01
Selenium	0.005	0.033	0.010	<0.001	0.025	0.460
Silver	0.0006	0.002	0.002	<0.002	<0.002	<0.002
Thallium	0.002	0.006	0.01	<0.002	<0.002	0.003
Vanadium	<0.04	<0.04	<0.04	<0.01	<0.01	0.03
Zinc	0.195	0.046	0.03	<0.01	<0.01	<0.01

a = Kaiparowits Coal, Ultimate Analysis (wt. %, dry): Carbon 67.80, Hydrogen 4.72, Nitrogen 1.17, Sulphur 0.35, Ash 11.22, Oxygen 14.74

b = Not Reported

TABLE 4-34 GENERATION OF AQUEOUS WASTE FROM THE MOBIL-MTG PROCESS[31]

AQUEOUS PHASE ANALYSIS

COMPONENTS	% BY WT. IN H_2O
Formic Acid	0.2
Acetic Acid	0.02
Acetaldehyde	0.01
Acetone/Propionaldehyde	0.15
Methyl Ethyl Ketone/n-Butylaldehyde	0.05
Methanol	0.01
	0.44

MOBIL-MTG CHEMISTRY

FEED PRODUCT

$$nCH_3OH \longrightarrow (CH_2)_n + nH_2O$$

Material Balance: 100 kg ⟶ 44 kg + 56 kg

Energy Balance: 100 BTU ⟶ 95 BTU + 0 BTU

TABLE 4-35

CHARACTERISTICS OF DE-IONIZED WATER LEACHATE FROM TEXACO SLAG[18]

PARAMETER[a]	ILLINOIS NO. 6 COAL		KAIPAROWITS COAL	
	COARSE SLAG	FINE SLAG	COARSE SLAG	FINE SLAG
pH	6.0	7.1	9.6	8.9
TDS	NR[b]	NR	250	310
Conductivity (μmhos/cm)	100	600	53	135
COD	NR	NR	45	28
TOC	2	3	15	9.1
Ammonia	1.2	4.6	NR	NR
Anions				
Bromide	<0.1	<0.1	-	-
Chloride	1.5	2.2	-	-
Fluoride	4.9	8.7	-	-
Cyanide	<0.001	<0.001	-	-
Formate	<1	<1	-	-
Nitrate	0.4	0.5	-	-
Nitrite	<0.1	<0.1	-	-
Sulphate	26.9	313	-	-
Trace Elements				
Antimony	0.003	0.005	-	-
Arsenic	0.007	0.019	<0.01	<0.01
Barium	<0.38	<0.38	0.04	0.2
Beryllium	<0.001	<0.001	-	-
Boron	-	-	-	-
Cadmium	0.004	0.0006	-	-
Chromium	<0.002	0.002	0.015	0.003
Cobalt	0.029	0.028	<0.002	0.001
Copper	<0.003	0.016	0.03	<0.006
Flourine	4.9	8.7	-	9.0
Lead	0.005	0.008	-	-
Manganese	0.105	0.212	0.002	0.03
Mercury	<0.005	<0.005	0.01	<0.002
Molybdenum	<0.9	<0.9	-	-
Nickel	0.875	0.131	<0.02	-
Selenium	<0.009	0.027	<0.002	0.05
Silver	<0.002	<0.002	-	-
Thallium	<0.006	<0.006	-	0.001
Vanadium	<1.8	<1.8	0.14	0.16
Zinc	0.098	0.052	<0.09	<0.09

a - All units in mg/L unless otherwise noted.

b - NR = Not Reported.

TABLE 4-36 COAL PILE DRAINAGE SAMPLE FROM LINGAN GENERATING STATION [26]

PARAMETER	
pH	2.1
T.O.C.	2.0
Total Solids	5,720
Total Dissolved Solids	5,540
Total Suspended Solids	180
Hardness as $CaCO_3$	860
C.O.D.	42.9
Alkalinity as $CaCO_3$	-
FMA as $CaCO_3$	1,500
Oil & Grease	1.5
Turbidity (NTU)	7.8
Total Sulfur as Sulfate	3,700
Sulfate	3,600
Chloride	580
Fluoride	0.4
Ammonia as NH_4^+	0.6
Phenol (µg/L)	4.0
Cyanide as CN^- (µg/L)	<20
Thiocyanate as SCN (µg/L)	<0.5
Inorganic Phosphate as PO_4^{-3}	6.1
Total Phosphate as PO_4^{-3}	6.1
Aluminum	60
Antimony	1.7
Arsenic	0.650
Barium	<0.1
Beryllium	0.01
Boron	0.23
Cadmium	0.12
Calcium	27
Chromium	<0.05
Cobalt	0.85
Copper	0.56
Iron	500
Lead	0.1
Lithium	0.3
Magnesium	72
Manganese	21.3
Mercury (µg/L)	<1
Molybdenum	<0.1
Nickel	1.5
Potassium	2.9
Selenium	<0.02
Silica as SiO_2	22
Silver	0.03
Sodium	450
Strontium	1.3
Thallium	<0.2
Thorium	<0.06
Titanium	<0.3
Uranium (µg/L)	<5
Vanadium	<0.1
Zinc	5.4
Zirconium	<0.05

NOTE: All results in µg/L except where noted.

4.3.3. H-Coal Process Aqueous Wastes

Environmental baseline data generated during the operation of the 180 tonne/day H-Coal Catlettsburg pilot plant has provided the basis for the wastewater treatment strategy and projected wastewater and effluent characteristics reported in the Environmental Impact Statement for the Breckinridge Project commercial-scale facility.

The principal feature in the wastewater and overall water management strategy for the Breckinridge Project is the segregation and treatment for reuse of all waters potentially containing PAH compounds. These waters are ultimately evaporated in a separate high-solids cooling tower following treatment. The overall water flow schematic for the project is shown in Figure 4-13.

The detailed water balance for the proposed plant is shown in Figure 4-14. Those segregated process wastewaters thought to contain PAH compounds are: produced reaction water from the H-Coal raw product cooling operations (see Figure 4-3), Texaco gasifier grey quench water blowdown, direct contact (with products) steam condensate and the PAH high-solids cooling tower blowdown. All other wastestreams are directed to the non-process wastewater facility and the sanitary sewage treatment facility before final discharge, as shown in Figure 4-14.

A schematic of the wastewater treatment trains for process and non-process wastewaters is shown in Figure 4-15. The process wastewater pretreatment section consists of pH adjustment with caustic, preheating and ammonia, carbon dioxide, and hydrogen sulphide steam stripping, solvent extraction with MIBK solvent (Chem-Pro process), tar/oil separation, and wet air oxidation (Zimpro). Ammonia is

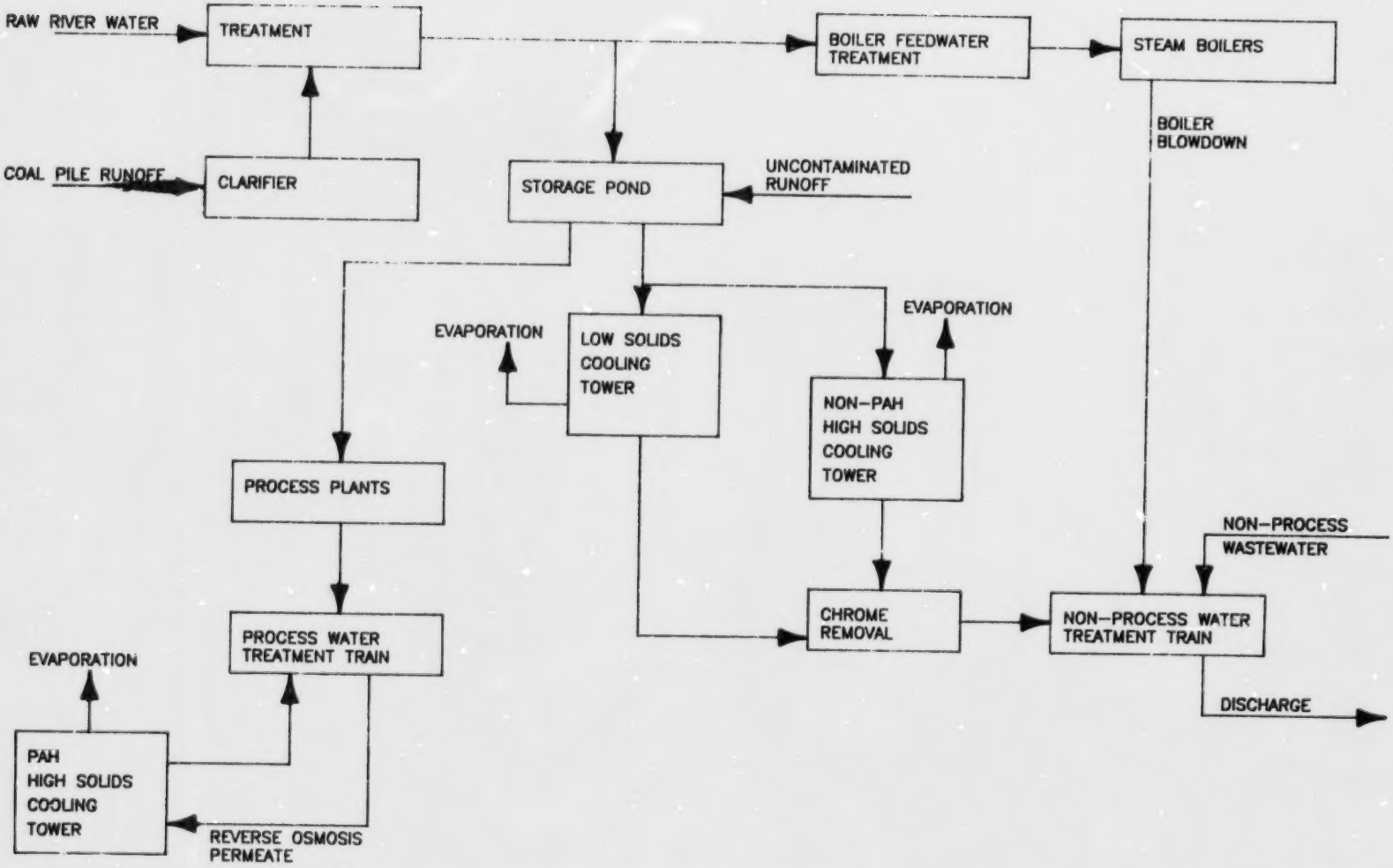
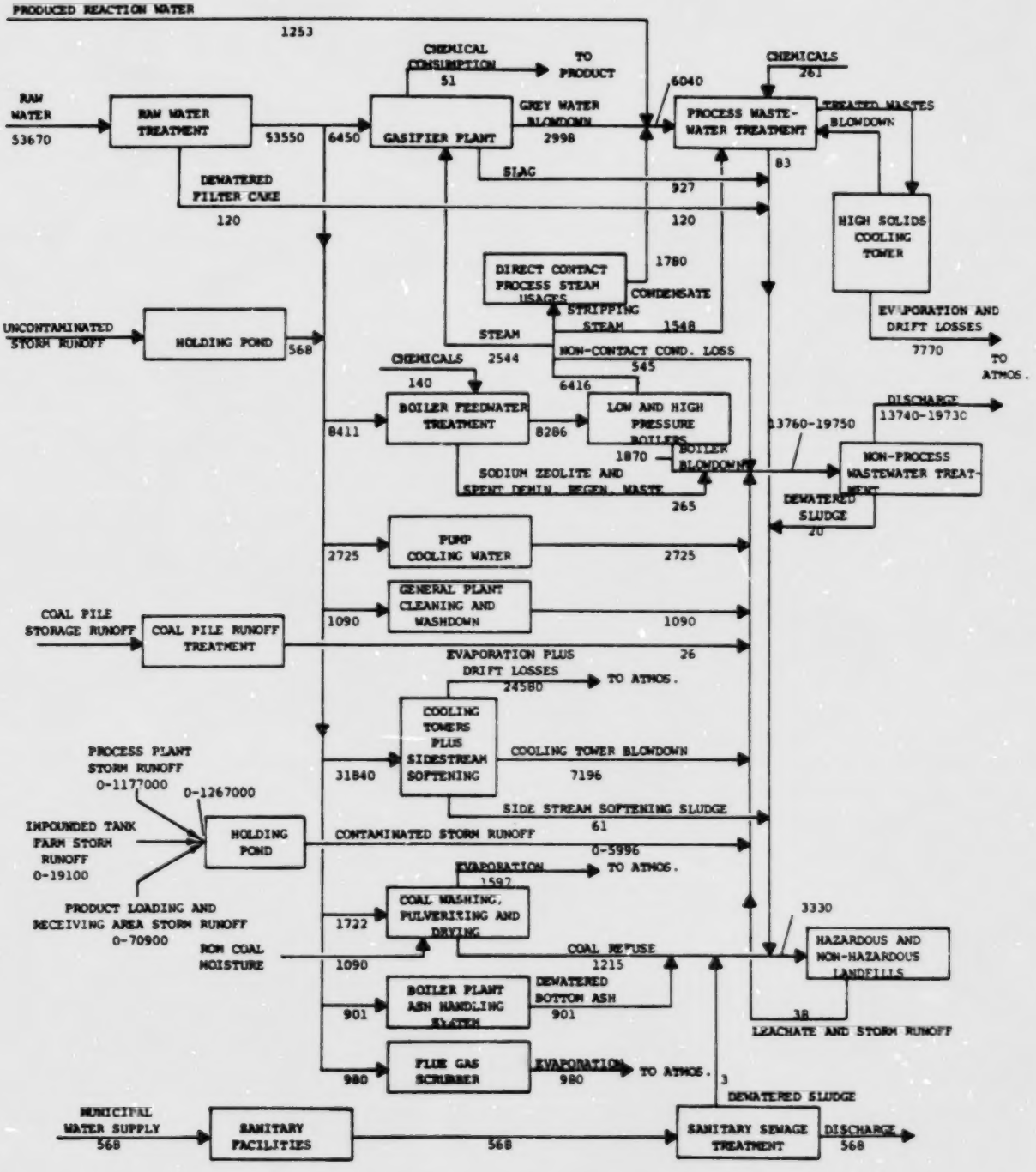


FIGURE 4-13 OVERALL WATER FLOW SCHEMATIC FOR H-COAL BRECKINRIDGE PROJECT (19)



NOTE: All Flows in m^3/day H_2O

FIG. 4-14 WATER BALANCE FOR THE H-COAL BRECKINRIDGE PROJECT

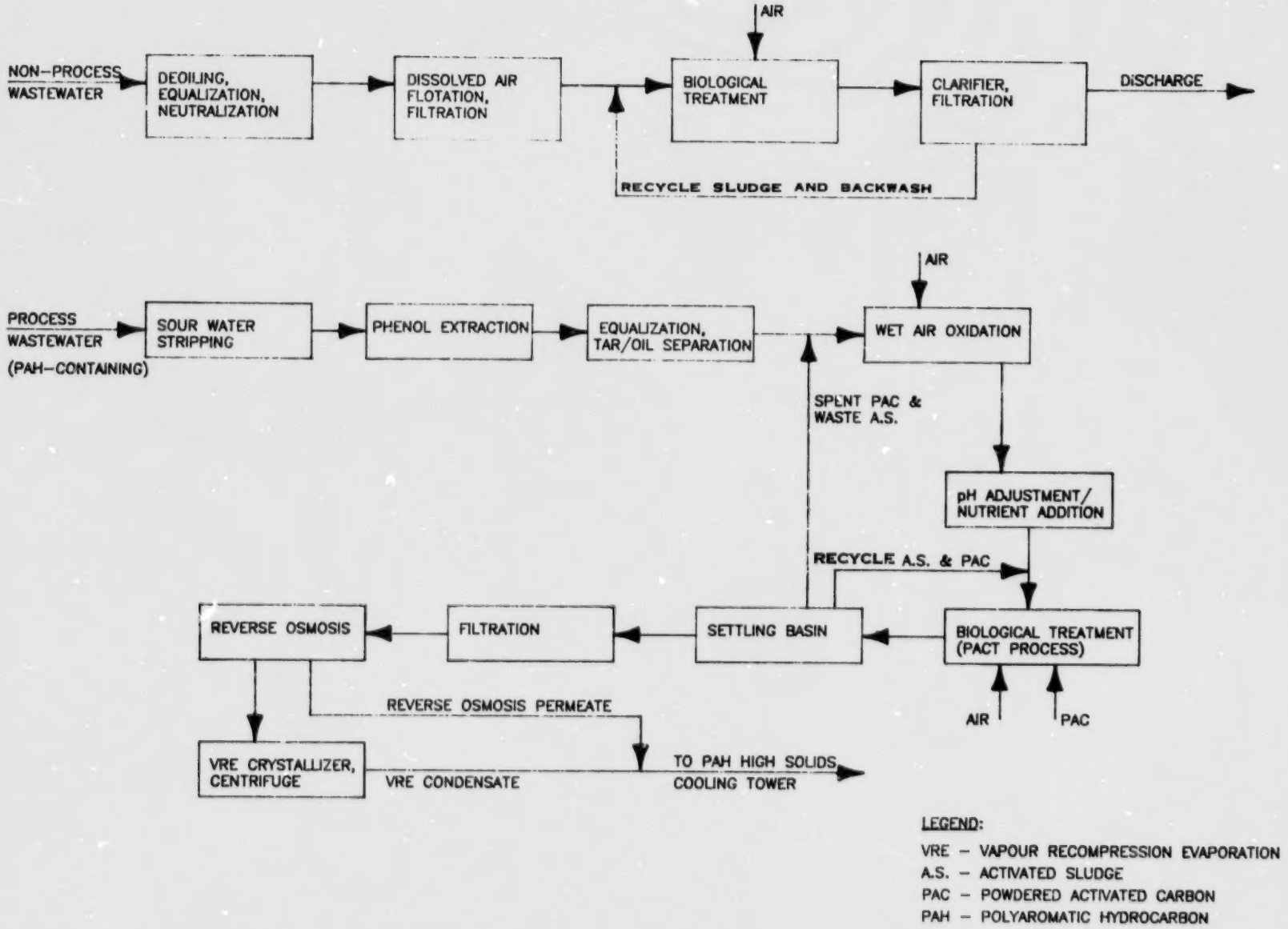


FIGURE 4-15 SCHEMATIC OF TREATMENT TRAINS FOR NON-PROCESS AND PROCESS WASTEWATERS GENERATED BY THE H-COAL BRECKINRIDGE PROJECT

recovered from the steam stripper off-gases in the U.S. Steel Phosam-W process. The wet air oxidation unit is expected to remove 85 percent of the influent COD.

Wet air oxidation process effluent is neutralized and fed to the Zimpro PACT (power activated carbon/activated sludge) biological treatment unit. Spent PAC and waste activated sludge would be continuously recycled to the wet air oxidation unit for PAC regeneration and waste sludge destruction. BOD removal in the PACT process is projected to be 95 percent according to design specifications. Supplemental phosphate nutrient would likely be required.

Settled and sand-filtered effluent from combined activated sludge/powdered activated carbon treatment would undergo tertiary treatment for dissolved solids removal before introduction to the cooling tower. Although presently under detailed study, it is expected that tertiary treatment will consist of reverse osmosis, projected to remove 95 percent of the dissolved salts. The concentrated brine stream from reverse osmosis would be evaporated in a vapour recompression evaporator unit. The RO permeate and evaporator condensate would ultimately be evaporated in the PAH high-solids cooling tower.

Non-process wastewaters would undergo conventional biological treatment following oil separation, neutralization, and dissolved air flotation oil and solids removal pretreatment stages. Following sand filtration, the effluent would be discharged.

The characteristics of non-process wastewaters, listed as utility and storm water runoff of waters, are tabulated in Tables 4-37 and 4-38. Coal pile runoff data for Cape Breton Sydney coal is presented in Table 4-36. Other potentially significant non-process wastewaters for which no

characterization data were available are: hazardous and non-hazardous landfill leachates, chemical cleaning wastes, and contaminated storm runoff from process plant, tank farm, and product loading and receiving areas.

The combined non-process wastewater characteristics after oil separation and as final effluent discharge from the plant are shown in Table 4-39. Projected removal efficiency of major pollutants by each unit operation in the treatment train is also given.

Treated sanitary and non-process wastewater effluent characteristics under minimum, average and maximum flow conditions (dry and storm weather conditions) are shown in Table 4-40.

Detailed information on the characteristics of the process wastewater streams and projected unit process pollutant removal profiles were not available for the H-Coal Breckinridge Project. Table 4-41 shows the combined sour water characteristics before and after steam stripping for the H-Coal Catlettsburg pilot-plant during the processing of Illinois No. 6 coal. The combined pilot-plant sour water consists of:

a) reactor effluent vapour separator wash (3,000 psi)
b) high pressure separator wash condensate (1,200 psi)
c) low pressure separator wash condensate (50 psi)
d) fractionator reflux drum water
e) vacuum tower vent (condensed steam) collector water

Bench-scale studies have addressed solvent extraction pretreatment by the Chempro process (MIBK solvent) and combined biological/activated carbon (PACT process) treatment of steam-stripped H-Coal sour water generated by the Catlettsburg pilot-plant processing Illinois No. 6

coal[32]. At a solvent-to-feed ratio of 0.067, total phenols were reduced from approximately 4,500 mg/L to between 200 - 400 mg/L in the Chempro process. The mean extracted wastewater COD was 2,000 mg/L. A sample of the extracted wastewater was subsequently treated in a single and two-stage bench-scale PACT treatment system. Feed and effluent characteristics from the bench-scale units are shown in Table 4-42. It is important to note that, due to the high effluent nitrate levels, denitrification or tertiary dissolved solids removal would be necessary before reuse or discharge of the PACT effluent. Further information is presented in Section 6 on H-Coal sour water characteristics and the effect of steam-stripping and solvent extraction pretreatment operations on subsequent biodegradability.

The applicability of the proposed Breckinridge Project wastewater management scheme to an H-Coal plant located on Cape Breton Island will depend on at least two main factors:

1) National, provincial and local environmental guidelines concerning aqueous discharges to freshwater or the ocean.

2) The suitability of once-through seawater cooling to large areas of the plant to alleviate freshwater demand.

Other factors which may impinge on the wastewater management strategy are: resource recovery (marketability of by-product ammonia and phenol), use of a centralized plant for both coal liquefaction and refinery syncrude upgrading wastewaters (Pt. Tupper Refinery) and possible utilization of modified coal liquefaction scheme (process coal and/or heavy oil feedstocks, utilize new two-stage process under development by HRI and others).

TABLE 4-37 SOURCES OF UTILITY WASTEWATER AND THEIR ANTICIPATED WASTEWATER CHARACTERISTICS FOR THE H-COAL BRECKINRIDGE PROJECT[19]

WASTEWATER CHARACTERISTICS	COOLING TOWER BLOWDOWN (UNTREATED)	COOLING TOWER BLOWDOWN (TREATED)	COMPOSITE BOILER BLOWDOWN	VESSEL AND TANK DRAINS	STEAM CONDENSATE LOSSES	PUMP COOLING WATER	SETTLED WATER FROM SLOP OIL TANKAGE	LAB SINK DRAINS	PLANT WASHDOWN AND DUST SUPPRESSION	COMPOSITE UTILITY WASTEWATER
Flow, M^3/min	5.00	5.00	1.30	0.15	0.38	1.89	0.04	0.04	0.76	9.55
m^3/day	7,195	7,195	1,870	218	545	2,725	4.5	54.5	1,090	13,753
Temp., ^oF (winter)	70	70	150	50	100	55	50	50	35	76
(summer)	85	85	150	80	175	85	85	85	80	97
BOD_5, soluble	86	86	101	3,000	0	100	3,000	500	250	160
COD, soluble	288	288	306	5,000	0	300	5,000	1,000	500	394
TOC, soluble	100	100	212	3,000	0	150	3,500	600	320	200
TDS	1,745	1,750	2,933	2,500	200	500	3,500	2,500	200	1,500
Settleable Solids	10	0.5	54	50	0	5	10	10	100	17.4
NO_3 - NO_2	6.25	6.25	13.13	0	0	1.24	0	0	1.2	4
Ammonia (as N)	3	3	6.6	0	0	0	0	5	1.0	2.6
Thiocyanate	0	0	0	0	0	0	0	0	0	0
Cyanide	0	0	0	0	0	0	0	0.01	0	0
Sulfides	0	0	0	0	0	0	0	0	0	0
Aluminum	0.5	0.1	0.81	0	0	0.1	0	1.0	0	0.19
Sulfate	468	500	702	65	85	85	65	65	65	384
Chromium, total	10	0.5	0.16	0	0	0.02	0	0	0	0.29
Silica	20	2.0	33	5	0	4	5	5	5	6.8
Copper	0.09	0.09	0.15	0	0	0.02	0.15	0	0	0.07
Fluoride	1.05	1.05	1.76	0.2	0	0.21	0.3	0.2	0.2	0.85
Zinc	2.30	0.46	0.49	0	0	0.06	0.49	0	0	0.12
Chloride	220	220	176	20	21	21	21	50	21	146
Phenols	5.0	5.0	0.2	300	0	0	500	10	10	10.2
Iron	0.5	0.5	0.61	15	0	1.5	5	0	0	1.32
Cadmium	0.04	0.04	0.065	0	0	0.008	0.04	0	0	0.032
Lead	0.04	0.04	0.073	0	0	0.009	0.04	0	0	0.009
Arsenic	0.01	0.01	0.024	0	0	0.003	0.01	0.01	0	0.009
Mercury	0.0035	0.0	0.0057	0	0	0.0007	0.0035	0	0	0.0009
Manganese	0.950	0.950	1.546	0	0	0.190	0.950	0	0	0.7480
Phosphorous, total	0.9	0.9	5.9	0	0	0.9	0.0	1.0	0.2	1.47
Colour (unit)										
pH (unit)		8.5	11.6							

TABLE 4-38 Sources of Contaminated Stormwater Runoff and Their Anticipated Wastewater Characteristics for the H-Coal Breckinridge Project [19]
(All units in mg/l except as noted)

Wastewater Characteristics	Contaminated Process Plant Storm Runoff	Impounded Tank Farm Storn Runoff	Product Loading & Receiving Area Storm Runoff	Leachate and Runoff from Landfill	Combined Contaminated Stormwater Runoff
Flow, m^3/d	0-1, 100	0-3, 500	0-13, 000	0 - 200	200 - 1100 *
Temp., °F (winter)	35	35	35	50	35
(summer)	70	70	70	70	70
BOD_5, soluble	100	100	150	600	142
COD, soluble	200	150	200	1000	199
TOC, soluble	150	120	160	650	157
TDS	100	100	200	500	178
Settleable Solids	100	100	100	10	99
NO_3 - NO_2	1.2	1.2	1.2	1.0	1.2
Ammonia (as N)	1.0	1.0	1.0	5	1.0
Thiocyanate	0	0	0	0	0
Cyanide	0	0	0	0	0
Sulfides	0	0	0	0	0
Aluminum	0	0	0	0	0
Sulfate	65	65	65	165	66
Chromium, total	0	0	0	0.1	0.0011
Silica	5	5	5	5	5
Copper	0	0	0	0.1	0.0011
Fluoride	0.2	0.2	0.2	0.2	0.2
Zinc	0	0	0	0.1	0.0011
Chloride	21	21	21	120	22
Phenols	50	10	10	100	13.5
Iron	5	5	5	0.5	5.0
Cadmium	0	0	0	0	0
Lead	0	0	0	0	0
Arsenic	0	0	0	0	0
Mercury	0	0	0	0	0
Manganese	0.800	0.800	0.800	0.800	0.800
Phosphorous, total	0.2	0.2	0.2	5.0	0.25

* Controlled flow rate from impoundment to the treatment.

TABLE 4-39 Major Pollutant Non-Process Wastewater Treatment Plant Profiles (Dry Weather Conditions) for H-Coal Breckinridge Project (19)
(All units in mg/l except as noted)

Wastewater Characteristics	Oil/Water Separator Effluent	Dissolved Air Flotation		Primary Filters		Biological Treatment		Tertiary Filters		Treated Effluent
		Rem %	Eff.	Rem %	Eff.	Rem %	Eff.	Rem %	Eff.	
Temperature, °F (Winter)	73									73
(Summer)	95									95
TSS	250	80	50	40	30	-	30	50	15	15
Oil & Grease	200	85	30	33	20	25	15	33	10	10
BOD_5, Total	230	30	162	-	158	85	23	35	15	15
BOD_5, Soluble	151	-	151	-	151	95	8	-	8	8
COD, Total	800	44	445	-	420	70	123	10	110	110
COD, Soluble	370	-	370	-	370	80	75	-	75	75
Phenol	10.4	-	10.4	-	10.4	97	0.3	-	0.3	0.3
Ammonia (ASN)	2.5	-	2.5	-	2.5	-	5.0 (2)	-	5.0	5.0
TDS	1403									1400
$NO_3 - NO_2$	5.1									5.1
Thiocyanate	0									0
Cyanide	0									0
Sulfides	0									0
Aluminum	0.18									0.18
Sulfate	361		381 (1)							381
Chromium, Total	0.27									0.27
Silica	6.7									6.7
Copper	0.065									0.065
Flouride	0.8									0.8
Zinc	0.297									0.297
Chloride	137									137
Iron	1.59									1.59
Cadmiun	0.03									0.03
Lead	0.0083									0.0083
Arsenic	0.0083									0.0083
Mercury	0.0008									0.0008
Manganese	0.75									0.75
Phosphorus	1.38						1.0 (2)			1.0
pH										6-9

(1) Based on 20 ppm H_2SO_4 addition rate for pH control.

(2) Ammonia and phosphorus will be added to supply biological nutrient requirements. Concentrations indicated are residual operating levels.

TABLE 4-40 PROJECTED CHARACTERISTICS OF LIQUID EFFLUENTS FROM NON-PROCESS WASTEWATER TREATMENT TRAINS, H-COAL BRECKINRIDGE PROJECT[19]

PARAMETER [a]	TREATED SANITARY EFFLUENT			TREATED NONPROCESS WATERS		
	MINIMUM	DAILY AVERAGE	MAXIMUM	MINIMUM	DAILY AVERAGE	MAXIMUM
Flow Rate, M^3/day	284	568	1,136	13,630	13,630	19,680
pH	6	-	9	6	-	9
Temperature (winter), ^oF	35	40	55	55	60	75
Temperature (summer), ^oF	65	80	85	80	88	95
BOD (5-day)	10	30	40	13.3	15	38.4
COD	72	216	288	95.8	110	277
Fecal Coliform (/ml)	-	-	400[b]	-	-	-
Total Suspended Solids	10	30	40	13.3	15	38.4
Total Dissolved Solids	-	-	-	-	1,400	-
Settleable Matter	0.1	0.1	0.2	0.1	0.1	0.2
Fluoride	-	-	-	-	0.8	-
Chloride	-	-	-	-	137	-
Chlorine	0.3	0.4	0.5	-	-	-
Ammonia, as N	15	20	40	14.2	20.5	43.9
Nitrate & Nitrite	-	-	-	-	5.1	-
Phosphorus	-	-	-	-	1.38	-

a - mg/L unless otherwise stated.

b - As a geometric mean based on 5 samples per month.

TABLE 4-40 (cont'd)

PARAMETER [a]	TREATED SANITARY EFFLUENT			TREATED NONPROCESS WATERS		
	MINIMUM	DAILY AVERAGE	MAXIMUM	MINIMUM	DAILY AVERAGE	MAXIMUM
Cyanide	-	-	-	0.05	0.1	0.2
Thiocyquate	-	-	-	-	0	-
Sulfate	-	-	-	-	381	-
Aluminum	-	-	-	0.3	0.4	0.4
Arsenic	-	-	-	-	0.0083	-
Cadmium	-	-	-	-	0.03	-
Chromium	-	-	-	0.4	0.27	0.9
Copper	-	-	-	0.3	0.065	0.4
Iron	-	-	-	-	1.59	-
Lead	-	-	-	-	0.0083	-
Zinc	-	-	-	0.3	0.297	0.4
Manganese	-	-	-	-	0.75	-
Mercury	-	-	-	-	0.008	-
Phenols	-	-	-	0.2	0.3	0.6
Oil and Grease	-	-	-	9	10	13

a - Units in mg/L.

TABLE 4-41 H-COAL COMBINED PROCESS WATER CHARACTERISTICS [32]
(all values in mg/L unless otherwise stated)

PARAMETER	COMBINED SOUR WATER	STRIPPED SOUR WATER
BOD	–	10000
COD	22000	11000
TOC	6500	5000
Total Phenols	4800	4500
Phenol	2500	2500
Cresols	2000	2000
Resorcinol	300	30
TKN	7000	250
NH_3-N	8000	150
NO_3-N	5	5
NO_2-N	5	5
CN^2	25	15
Total P	1	0.05
Oil & Grease	100	75
Total Alkalinity	20000	50
CO_3	10000	100
HCO_3	10000	100
TDS^3	2000	2000
TSS	25	300
TVSS	20	275
TVDS	1500	1500
pH(units)	10	5.4
Boron	30	30
Silicon	5	ND
Calcium	5	3
Magnesium	2	2
Iron	0.2	20
SO_4-S	–	50
Chlorides	1500	1500
Sodium	60	800
Fluorides	5	5
Antimony	0.06	0.06
Arsenic	0.01	0.01
Cadmium	ND	ND
Chromium	8	50
Copper	ND	ND
Lead	0.02	0.01
Mercury	0.01	0.01
Nickel	0.01	0.01
Strontium	0.01	0.01
Titanium	ND	ND
Zinc	0.05	0.05

ND - not detected

TABLE 4-42

PACT BENCH-SCALE PERFORMANCE (32)

11-29-81 - 12-12-81

		SINGLE STAGE	TWO-STAGE	
			FIRST STAGE	SECOND STAGE
SRT, days		30.	5.	30.
HRT, hours		24.	8.	24.
Activated Carbon Dose, mg/l		500.	500.	500.
BOD_5, mg/l	Feed	692.	692.	6.
	Effluent	8.	6.	<6.
COD, mg/l	Feed	1691.	1691.	427.
	Effluent	322.	427.	165.
DOC, mg/l	Feed	509.	509.	104.
	Effluent	86.	104.	40.
TKN, mg/l	Feed	227.	227.	191.
	Effluent	9.7	191.	4.6
NH_3-N, mg/l	Feed	205.	205.	186.
	Effluent	<1.0	186.	<1.0
NO_3-N, mg/l	Feed	<1.0	<1.0	11.0
	Effluent	225.	11.0	240.
Color, APHA	Feed	7758.	7758.	2660.
	Effluent	3235.	2660.	946.
Phenols, mg/l	Feed	219.	219.	0.92
	Effluent	0.82	0.92	0.29

4.3.4. Lurgi Ruhrgas Pyrolysis/Power Generation Aqueous Wastes

To date, information on aqueous streams emanating from the LR Pyrolysis process has not been made available in the literature. The major aqueous wastestream from the LR Pyrolysis process is expected to be the pyrolysis product quench water condensate.

Since flash pyrolysis generates a much higher proportion of heavy aromatic tars than gasification or direct hydrogenation processes (due to less severe conditions and an un-hydrogenated environment), it is anticipated that significantly greater levels of phenolic, polynuclear aromatic, and sulphur and nitrogen-containing organic species will be extracted into the product quench liquor emanating from the LR Pyrolysis process. This may in turn dictate an approach to pretreatment other than solvent extraction, such as wet air oxidation, to render the wastewater biodegradable since PAH and hetero-atom organics may be poorly extracted. In addition, the formation of heavy colour-forming polymeric substances from polyhydric phenols, as has been observed on exposing H-Coal process sour water to the air, may necessitate the use of wet air oxidation pretreatment or carbon filtration/reverse osmosis tertiary treatment to remove these compounds from the wastewater before reuse or discharge (see Section 6.3.).

Other significant aqueous waste streams expected to be generated by an LR Pyrolysis/Power Generation facility are: naphtha hydrotreater sour water, boiler ash transport water blowdown (from coal, char, and gas co-firing), char and coal storage pile runoff, plant washdown and chemical cleaning wastes, ash disposal site runoff and cooling tower blowdown. Information on the characteristics of these streams was not available in the literature.

5. COAL CONVERSION WASTEWATER TREATMENT TECHNOLOGY

At the present time, the SASOL II plant in South Africa is the only modern full-scale operation from which an evaluation of current coal conversion wastewater control technology can be made. Environmental information for alternate coal conversion technologies likely to be integrated into stand-alone plants in the next decade is available only from bench-scale studies with synthetic wastes or wastewaters generated by PDU or pilot-scale units. Thus, much of this information may not reflect actual performance on the blended wastestreams generated by commercial-scale processes from the entire plant. Optimization of an overall water management strategy for pioneer plants planned or under construction at the present time will undoubtedly represent a significant part of initial plant "shakedown" activity, as has occurred at the SASOL II operation (see Appendix B).

Wastewater control technologies to be considered in this section are those proposed for treatment of process-generated wastewaters in full-scale coal conversion plants including the SASOL II and III operations and those now under construction or in the final planning stage for construction in North America (see Appendix A). Since the overall effectiveness of a multi-stage treatment train is difficult to predict from the bench-scale data, the control technologies will be considered on an individual basis. The implications of integrating these processes in a partial or zero-discharge scheme in a full-scale plant is addressed in a separate discussion.

5.1. Physical/Chemical Treatment

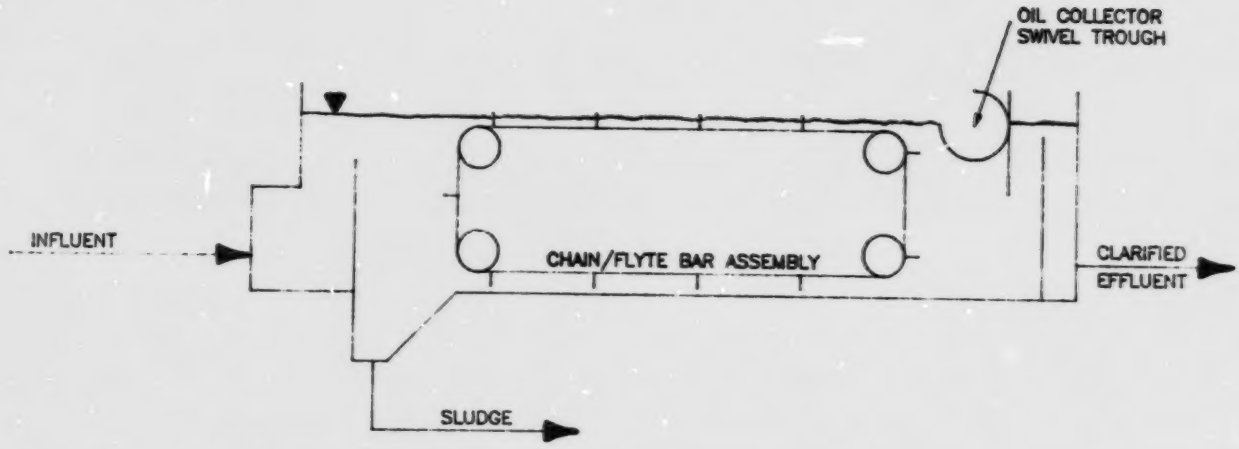
5.1.1. Gravity Separation Processes

With the exception of high-temperature entrained flow gasifiers such as the Texaco gasifier, coal conversion processes generate a tar and heavy oil fraction, a portion of which remains with the raw product quench liquor blowdown. Gravity oil separators, developed for use in petroleum refineries, are therefore proposed as the first stage in the treatment of these and other plant oily wastes such as process and storage tank washdown and runoff or product distillation steam condensates.

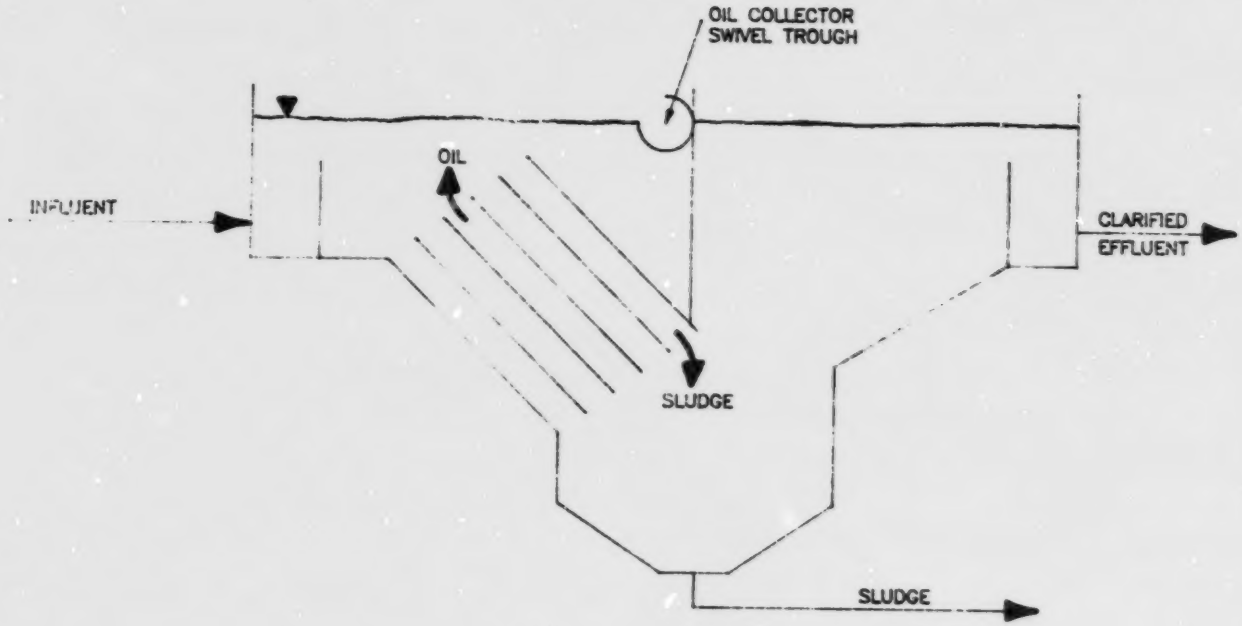
The most commonly used tar/oil separators are the API Separator and the Parallel Plate Separator shown diagramatically in Figure 5-1. Typically, 60 - 90 percent of the flotable oil and 10 - 50 percent of the suspended solids can be removed, depending on the presence of emulsions[33].

Dissolved air flotation is used for primary separation where there is a small difference in specific gravity between oil/suspended solids and water or emulsions cannot be effectively broken by pH reduction. Otherwise it is generally used after conventional gravity separation. The addition of chemical flocculating agents or organic polymer coagulant aids is usually practised to condition the influent.

Under alkaline pH conditions, heavy metals adsorbed on suspended solids would be removed. In addition, alkaline conditions would also enhance removal of soluble organics such as phenol. Phenol removal is reported to be in the range of 25 - 50 percent[34]. A schematic of the dissolved air flotation process is shown in Figure 5-2.



API SEPARATOR



PARALLEL PLATE SEPARATOR

FIGURE 5-1 GRAVITY SEPARATORS FOR PETROLEUM WASTEWATER

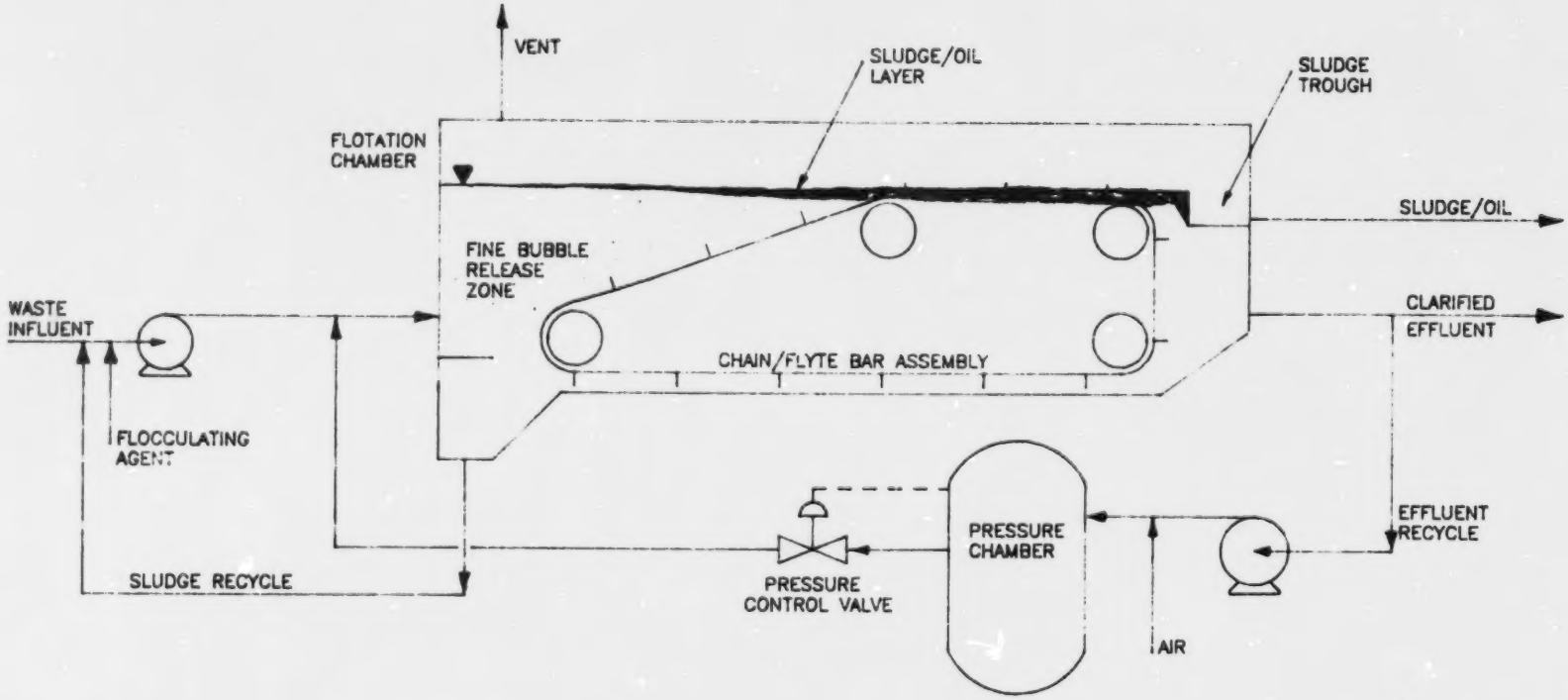


FIGURE 5-2 DISSOLVED AIR FLOTATION PROCESS (RECYCLE FLOW PRESSURIZATION)

Specific information on the performance of primary tar/oil separation processes with gas liquor condensates was not available.

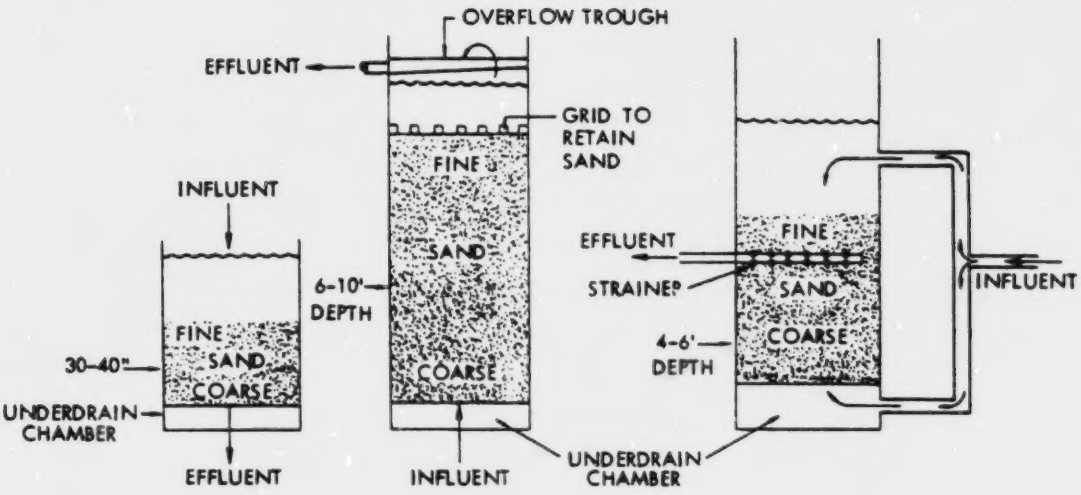
5.1.2. Filtration

Filtration suspended solids removal may be used in the primary treatment train to reduce contaminant load and potential plugging in subsequent processes (sandfilter used as SASOL II before Phenolsolvan process), or after secondary treatment as an effluent polishing step. The choice of filter media depends on the size range and nature of the solids to be removed. The addition of chemical flocculants prior to filtration will enhance removal of fine suspended solids and adsorbed heavy metal species. Removal of fine particulates by multi-media filtration employing fine sand, diatomaceous earth, anthracite or charcoal, is generally practised prior to reverse osmosis or activated carbon treatment stages[35].

The filter backwash is recycled to the primary gravity separation unit. In cases where filtration is used in the primary treatment train, it is likely that the media will eventually become fouled with heavy organic compounds. Operational data for the SASOL II wastewater sand filtration treatment step were unavailable. A schematic of conventional filter configurations is shown in Figure 5-3.

5.1.3. Dissolved Gas Removal/Ammonia Recovery

Quench liquors from coal conversion and product hydrotreating processes typically contain dissolved CO_2, COS, H_2S, and NH_3. Dissolved gas removal processes originally developed for petroleum refinery wastewater treatment, some of which are tailored to recovery of the ammonia fraction as a by-product, have been proposed for coal



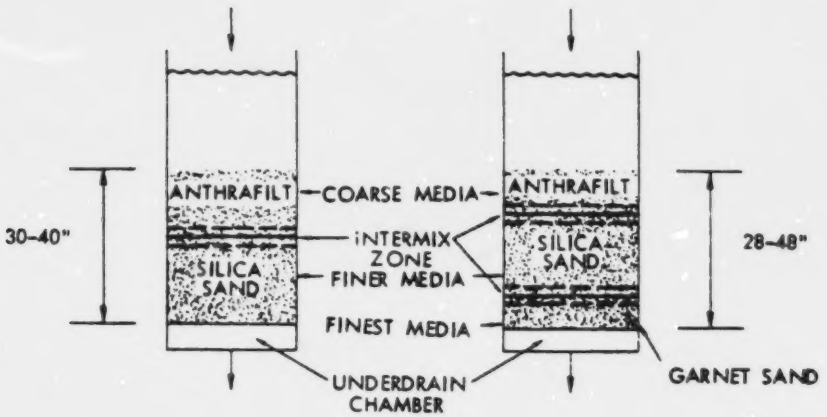


FIGURE 5-3 CONVENTIONAL FILTER CONFIGURATIONS[35]

conversion plant wastewater treatment systems. These processes are discussed separately below:

Steam Stripping

A schematic of the steam stripping process is shown in Figure 5-4. Preheated sour water is contacted counter-currently with steam over packing or trays. Stripping efficiency of the various dissolved substances is a function of pH. Removal of acid gases (H_2S, COS, CO_2) is promoted under acidic conditions while alkaline conditions favour ammonia removal. pH adjustment prior to steam stripping is, however, very costly due to inherently high buffering capacity of the wastewater. In cases where the feed coal has a high chloride content, alkaline pH adjustment requirement may be very large since a large fraction of the ammonia will be in a bound state.

Steam stripping also removes cyanide, thiocyanate and light polar organics to some extent depending on the overall characteristics of the wastewater[36]. The data presented in Table 4-41 show the effect of steam stripping on H-Coal combined sour water generated by the Catlettsburg H-Coal pilot plant.

USS Phosam-W Process

The Phosam-W process is shown diagramatically in Figure 5-5. Ammonia in the overhead vapour stream from a steam stripper is initially absorbed in an ammonium phosphate solution they subsequently released in a stripper and recovered in a distillation unit as 99 percent pure anhydrous ammonia. Due to the proprietary nature of this process, data were unavailable on the performance of this process on coal conversion wastewaters. The process has been reported to be successful in treating coke plant wastewater. A detailed

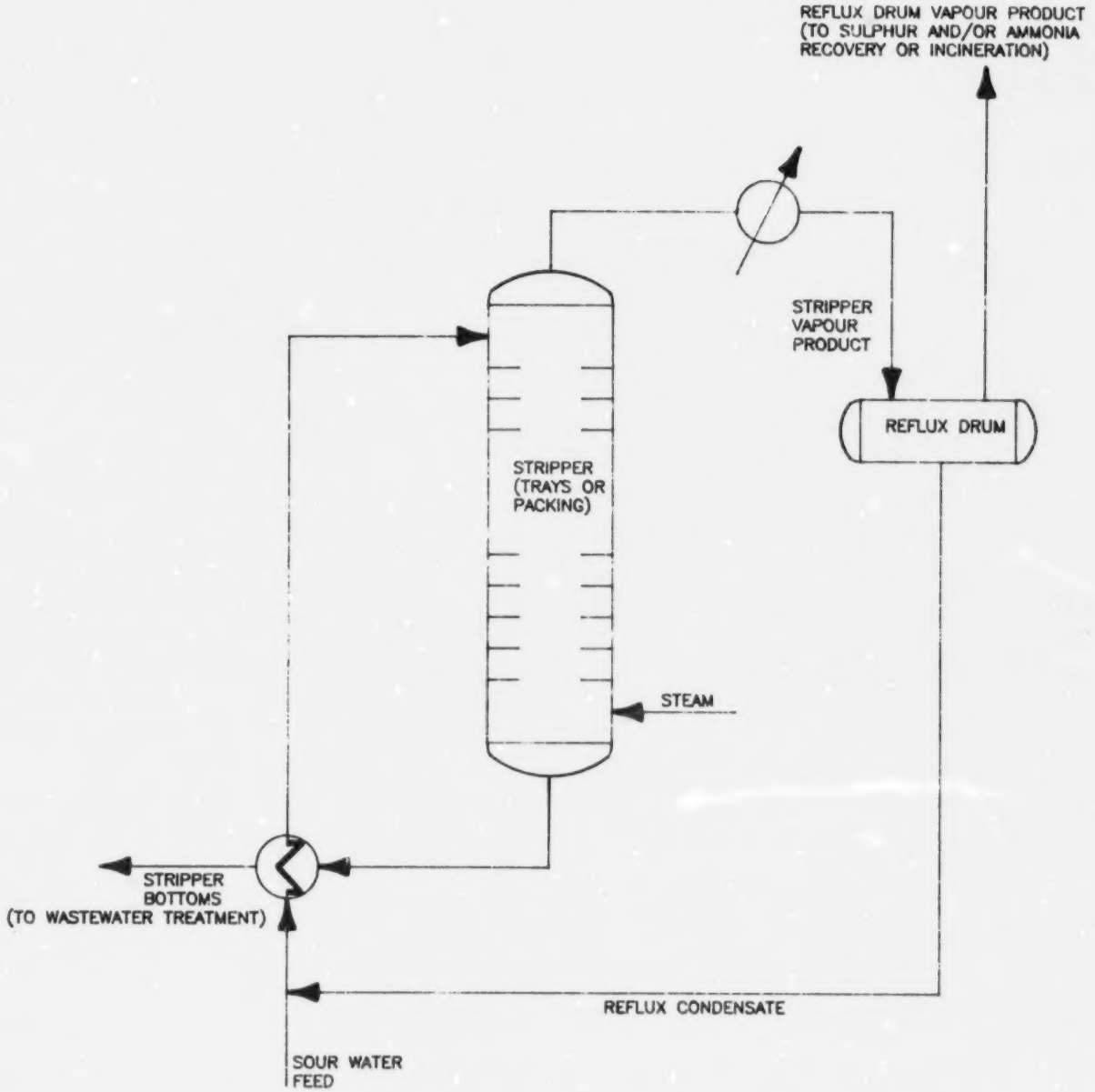


FIGURE 5-4 REFLUXED SOUR WATER STRIPPER

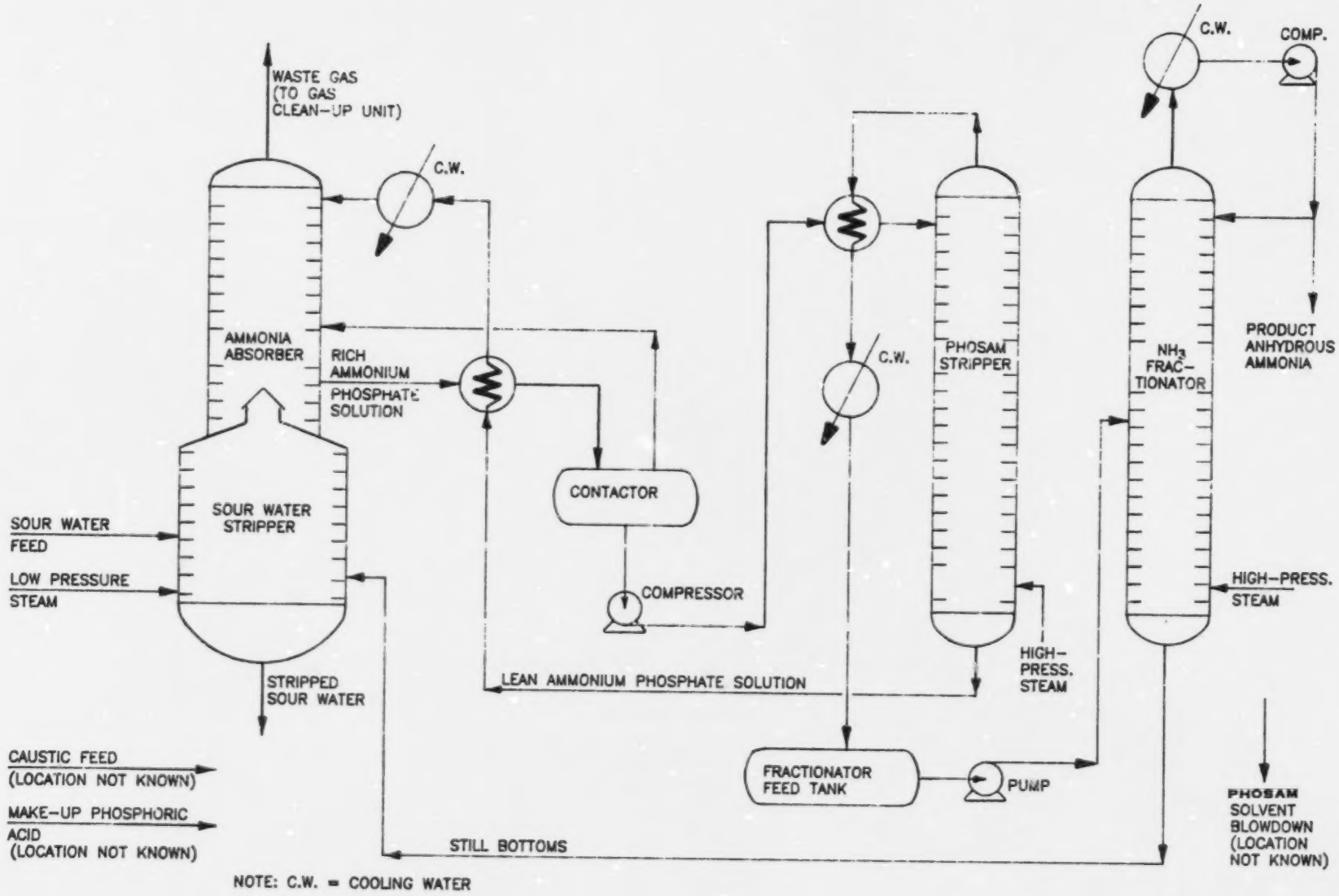


FIGURE 5-5 FLOW SCHEMATIC OF THE USS PHOSAM-W PROCESS (37)

description of projected design and associated operating conditions for the Phosam-W process as applied to coal gasification wastewaters is given in reference 37.

Chevron WWT Process

Chevron WWT process is shown schematically in Figure 5-6. Degassed (volatile organics) sour water is stripped in two stages, removing acid gases in the first stage and ammonia in the second stage. H_2S in the second stage overhead ammonia vapour is removed in cold aqueous ammonia scrubbers. The scrubber overhead ammonia vapour is flashed to concentrate the anhydrous ammonia by-product.

To date, the Chevron WWT process has been successful in treating refinery wastewaters containing both H_2S and NH_3 up to a maximum of 55,000 mg/L each[37]. Actual performance data, however, is unavailable due to the proprietary nature of the process. A detailed description of projected design and operating conditions for the Chevron WWT process as applied to coal gasification wastewaters is given in reference 37.

5.1.4. Solvent Extraction

With the exception of high-temperature entrained flow gasifiers, coal conversion process raw product quench liquors contain high levels of phenolic compounds. Solvent extraction developed initially for coal coking and petroleum refinery applications, has been successfully used at SASOL I for recovering phenol as a by-product while significantly reducing the organic loading to the biological treatment system. The Phenolsolvan process used at SASOL I has, therefore, been incorporated in the SASOL II and III operations. The Chem-Pro process is the only other solvent extraction/phenol recovery process currently being proposed

for use in coal conversion plants. Available information on each of these processes is presented below:

Phenolsolvan Process

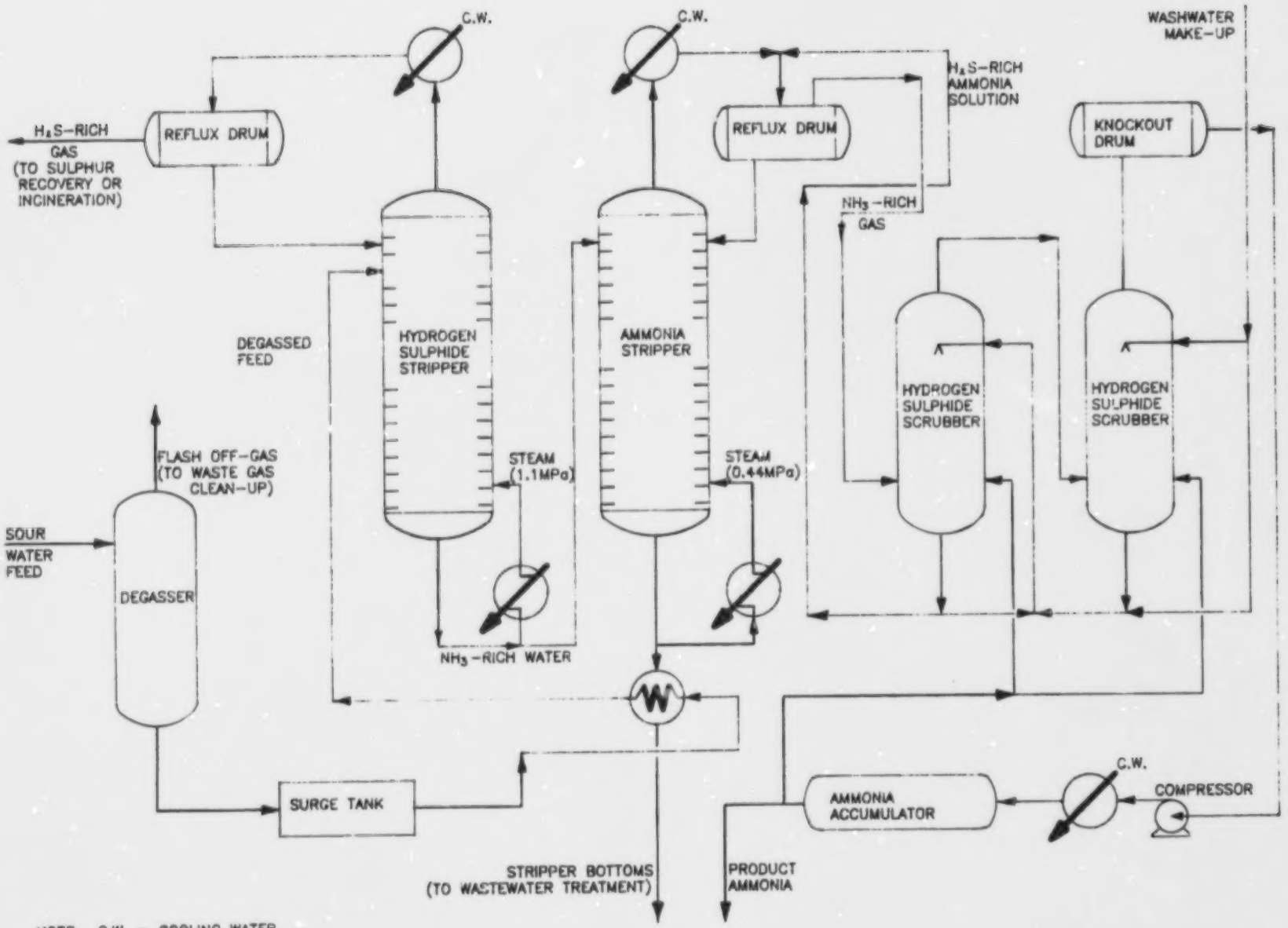
The Phenolsolvan process is shown diagramatically in Figure 5-7. Filtered wastewater is contacted with diisopropyl ether solvent in a continuous mixer-settler. The aqueous raffinate is scrubbed with nitrogen to remove residual solvent. The solvent-phase is distilled and steam stripped to recover the solvent leaving a crude by-product phenol stream.

The detailed performance of the Phenolsolvan process combined with steam stripping at SASOL I is shown in Table 4-26. The Phenolsolvan process at SASOL II is reported to recover 98 percent of the influent phenols with dihydric phenols being the major aqueous effluent phenol species (see Appendix B). Detailed information on design and operating conditions for the Phenolsolvan process are given in Reference 37.

Chem-Pro Process

The Chem-Pro process is shown diagramatically in Figure 5-8. The influent wastewater is contacted with MIBK solvent in a continuous reciprocating plate extraction column. The aqueous fraction is steam-stripped to remove residual solvent. The extract is distilled to recover the MIBK solvent producing a crude phenol by-product stream.

Steam-stripped sour water from the H-Coal process Catlettsburg pilot plant has been solvent extracted in the Chem-Pro process at the bench-scale. Influent total phenol concentrations averaging 4,500 mg/L were reduced to 200 - 400 mg/L total phenols in the effluent at a solvent-to-feed



NOTE: C.W. = COOLING WATER

FIGURE 5-6 FLOW SCHEMATIC FOR THE CHEVRON WWT PROCESS [37]

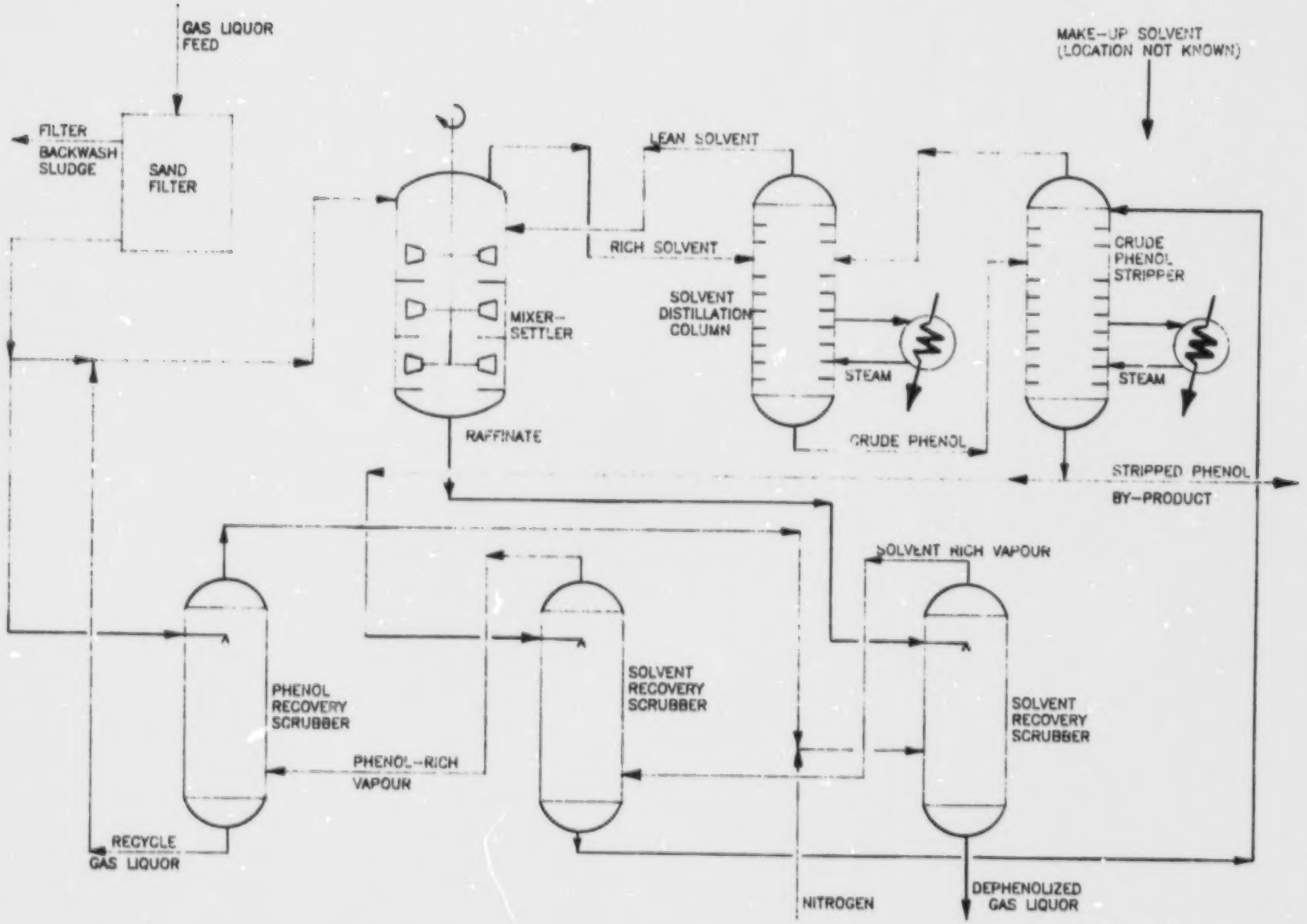


FIGURE 5-7 FLOW SCHEMATIC FOR THE PHENOLSOLVAN PROCESS (37)

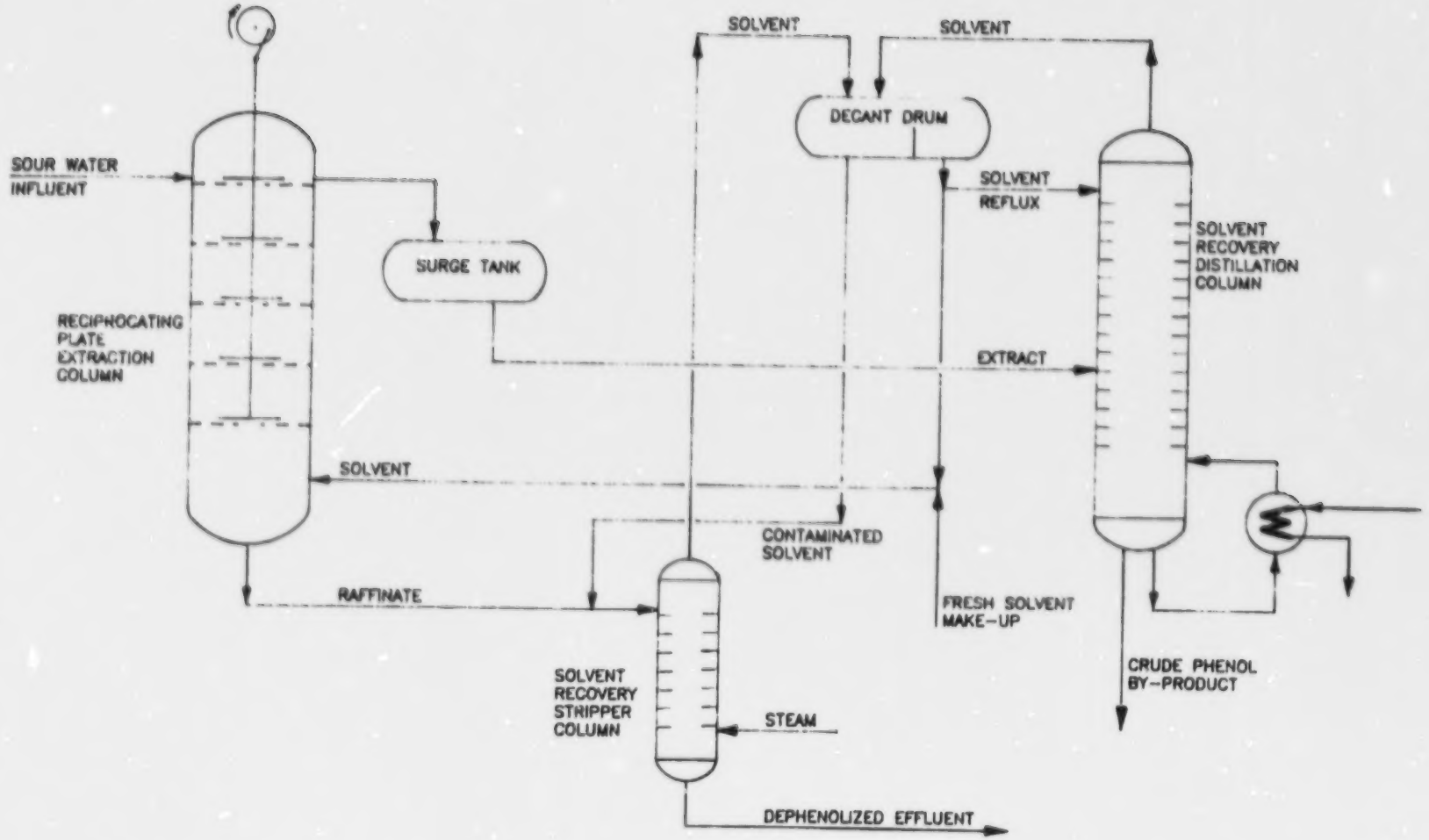


FIGURE 5-8 CHEM-PRO PROCESS

ratio of 0.067. The COD was reduced from 11,000 to 2,000 mg/L on average[32]. Detailed results on extraction of individual compounds were not obtained. Results from an additional pilot-scale evaluation on a 15,000 litre sample of H-Coal pilot plant wastewater were not available. Design information for the Chem-Pro process is given in reference 38.

5.1.5. Chemical Oxidation

Chemical oxidation of coal conversion wastewaters is an alternative to biological oxidation and may also be used to degrade bio-refractory compounds to lower molecular weight species to enhance their removal by carbon adsorption. Chemical oxidation methods applicable to coal conversion process effluents are discussed individually below:

Ozonation

Ozonation has been proposed as a means of reducing high-molecular weight bic-refractory compounds in biological treatment process effluent to lower molecular weight compounds suitable for carbon adsorption treatment. A bench-scale study on mild ozonation of H-Coal pilot plant biological treatment effluent showed that a significant reduction of up to 82 percent (at 50 minutes residence time) of effluent colour (believed to be polymerized phenolic compounds) was removed while the COD remained virtually unchanged[39]. Data on individual organic species degradation from bench-scale testing with Synthane process wastewater are shown in Table 5-1. Information on the effect of ozonation of coal conversion effluents on subsequent carbon adsorption is not currently available.

TABLE 5-1 PERFORMANCE OF BENCH SCALE OZONE TREATMENT OF SYNTHANE PROCESS WATER (ALL UNITS ARE mg/l EXCEPT pH AND OZONE RATE) (42)

Constituent/Parameter	Raw Wastewater	Ozone Rate		
		0.3 mg/ml	1.2 mg/ml	3 mg/ml
Phenol	2,320	2,340	2,225	820
Cyanide	2.28	1.31	0.6	1.02
Thiocyanate	418	445	450	240
Ammonia	4,250	4,200	4,010	3,710
COD	17,162	17,062	16,504	10,020
BOD	420	399	340	286
TOC	5,800	5,600	3,800	---
Pyridine and Picolines	---	17	17	9
Lutidines	---	5	6	1
Napthalene and Aniline	---	19	18	3
Toluidines	---	8	5	2
2-Methylnaphthalene and Xylidine	---	10	8	1
2-6-Xylenol	---	23	17	6
Quinoline	---	7	3	2
Phenol and O-cresol	---	2,084	1,990	443
M,p-cresol; 2,3 and 2,5-Xylenol	---	1,527	1,438	308
Methyl quinoline	---	22	24	0
2,3-Xylenol	---	44	44	14
3,5-Xylenol; m,p-ethylphenol	---	333	330	77
3,4-Xylenol	---	102	99	16
3-Ethyl-5-Methylphenol	---	54	55	23
C_3-Phenols	---	26	27	21
4-Indanol	---	47	40	16
Indol	---	55	50	16
pH	9.4	9.4	9.4	8.0

Wet Air Oxidation

The wet air oxidation process is currently being promoted by Zimpro Inc. for application to high strength hydrocarbon process wastewaters, as a biological sludge destruction process, as a spent carbon regeneration process, or a combination of the above[40]. A schematic of the wet air oxidation process is shown in Figure 5-9. Air or pure oxygen is introduced into a pressurized reactor along with the preheated waste stream and optional supplemental fuel (to maintain reaction temperature or produce energy export as process-generated steam). It is projected that an influent COD concentration of 20,000 mg/L is necessary to produce a self-sustaining reaction in terms of maintaining auto-thermal conditions[41].

The oxidation reactions are carried out at elevated temperatures in the aqueous phase by maintaining an adequate pressure in the system. Reactor conditions vary typically from temperatures of 175 to 315°C and pressures of 24 to 205 atm. The maximum permissible temperature is the critical temperature of water (374°C) above which the aqueous phase does not exist. Oxidation severity is primarily a function of temperature. Residence times are of the order of several minutes to several hours. The reactions are catalyzed by oxidizing catalysts such as Cu^{2+} ion.

The effluent consists of off-gases such as carbon dioxide, nitrogen oxide and steam, an aqueous effluent and ash. Acid gases such as H_2S, COS plus cyanide and thiosulphate are reported to be destroyed, under proper conditions, possibly eliminating the need for steam stripping upstream in some cases[34]. The performance of the Zimpro process on the IGT HYGAS process pilot plant quench condensate is shown in Table 5-2.

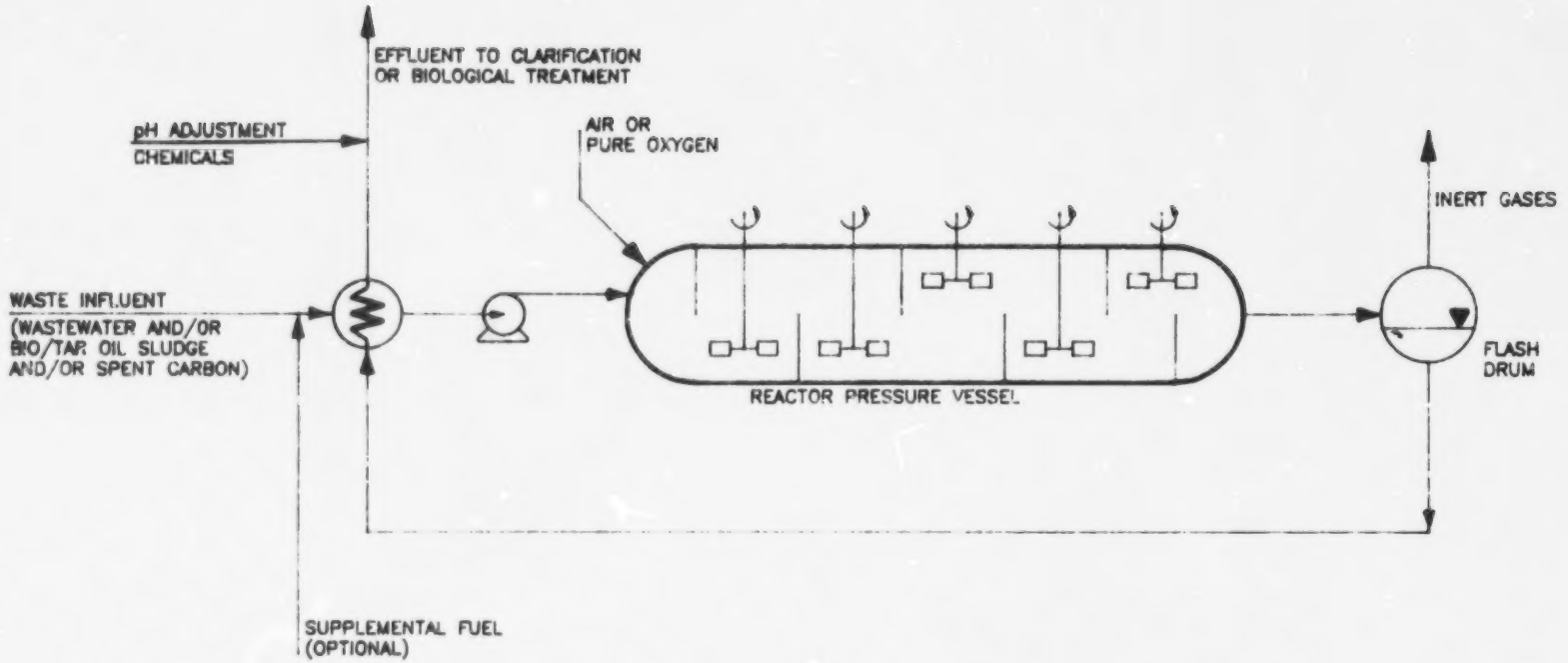


FIGURE 5-9 WET AIR OXIDATION PROCESS

TABLE 5-2 OPERATING EFFICIENCY FOR ZIMPRO WET AIR OXIDATION OF HYGAS PILOT PLANT WASTEWATERS[27]

PARAMETER	FEED	SAMPLE 694-56-1	% REMOVAL	SAMPLE 694-55-1	% REMOVAL	SAMPLE 694-58-1	% REMOVAL
Temperature, ^{o}K (^{o}F)	287 (56)	513 (464)	---	553 (536)	---	553 (536)	---
Time, min	---	60	---	60	---	60	---
Catalyst	---	NO	---	NO	---	YES	---
COD, g/l	13.7	4.9	64.2	3.3	75.9	1.0	92.7
Total Solids, g/l	1.75	1.36	22.2	1.16	---	2.46	---
Total Ash, g/l	0.36	0.34	5.5	0.37	---	0.38	---
pH	8.3	8.2	---	8.1	---	8.0	---
NH_3 as N, g/l	3.25	2.84	12.6	2.88	11.4	3.07	5.5
TKN, g/l	3.25	3.04	6.5	3.01	7.4	3.29	---
Total S, g/l	0.17	0.13	23.5	0.17	0	0.43	---
Total Halides as Cl, g/l	0.1	0.1	0	0.1	0	0.1	0
Phenol, mg/l	740	<1.0	<0.13	<1.0	0.13	<1.0	0.13
Cyanide, mg/l	0	0	---	0	---	0	---
Thiocyanate, mg/l	0	0	---	0	---	0	---
BOD_5, mg/l	---	2350	---	190	---	---	---

5.1.6. Tertiary Dissolved Organic and Inorganic Species Removal

Most current commercial-scale coal conversion plant designs, including the SASOL II and III operations, call for treated process wastewater reuse as make-up to wet cooling towers. A large reduction in treated wastewater dissolved salts and residual organics levels is therefore required in order to maintain an acceptable number of cooling cycles and prevent excessive biofouling. Technologies currently implemented at SASOL II or proposed for North American plants are reverse osmosis, forced evaporation, freeze concentration, ion exchange and carbon adsorption. Solar evaporation is not considered to be applicable in Canada. These processes are discussed individually below:

Reverse Osmosis

Reverse osmosis or hyperfiltration is a pressure-driven process where dissolved salts, organic molecules, and colloidal material are removed at a semi-permeable membrane interface. Membrane configurations are shown schematically in Figure 5-10. The effectiveness of reverse osmosis is a complex function of membrane and solution chemistry and pore or molecular size, respectively. Of greatest importance, in terms of treated water reuse, is the potential for effective organics removal by reverse osmosis such that the permeate may be suitable as boiler feedwater treatment make-up or significantly reduce biocide (eg. chlorine) levels in wet cooling towers due to reducing biofouling[27].

Typically, 50 to 90 percent of the influent is rejected as clean permeate. Performance data from bench-scale studies with H-Coal pilot plant bio-treated wastewater were not available. Table 5-3 shows the performance characteristics of reverse osmosis applied as the final stage in the

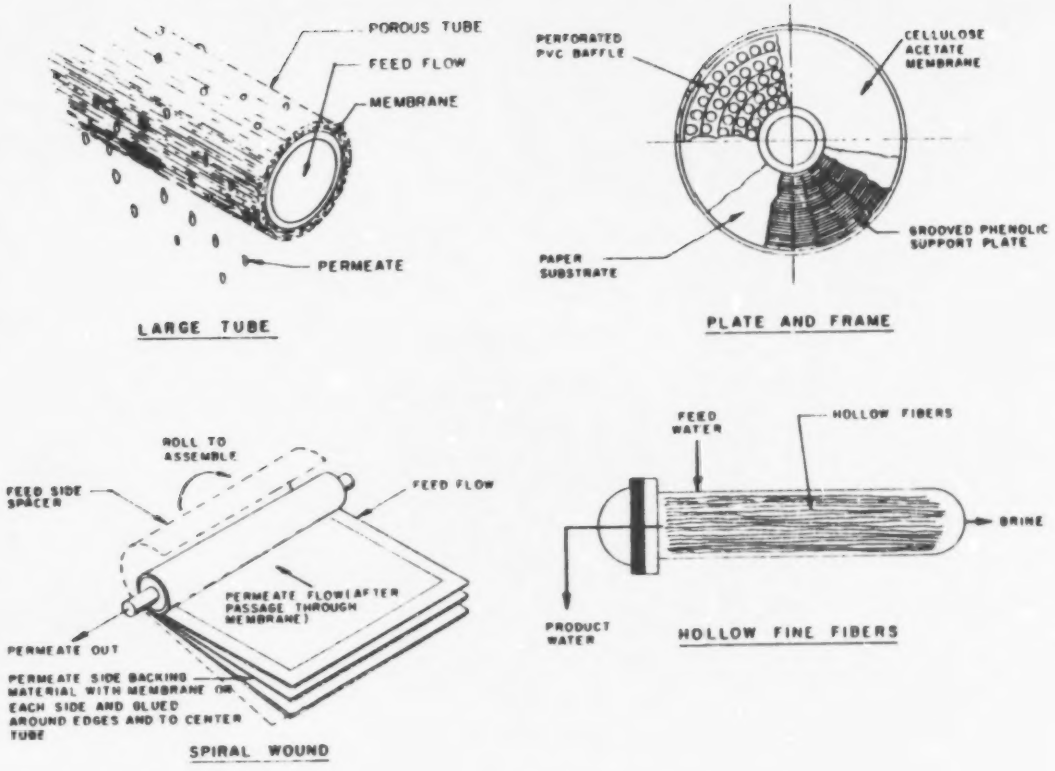


FIGURE 5-10 REVERSE OSMOSIS MEMBRANE CONFIGURATIONS[43]

TABLE 5-3 HYGAS RUN 79 QUENCH WATER QUALITY CHARACTERISTICS THROUGH REVERSE OSMOSIS TREATMENT[44]

SPECIFICATION[1]	BOD	COD	PHENOLICS	ORG-N	SCN^-	CN^-	NH_3-N	NO_3^--N	SO_4^{2-}	CALCIUM HARDNESS AS $CaCO_3$	TOTAL HARDNESS as $CaCO_3$	ALKALINITY as $CaCO_3$	pH UNITS	COND. umhos/cm	COLOR PT-CO UNITS	TDS	TURBIDITY NTU
							DuPont Polyamide Hollow Fibre Membrane[2]										
FEED	27	110	<0.20	5	2.1	5.0	80	160	2540	45	45	1080	7.8	6500	130	6100	1.2
PRODUCT	4	20	<0.04	2	0.4	0.1	0.5	0.55	10	0	0	100	7.6	155	<5	270	0.1
REJECT	265	780	-	9	-	12.0	225	290	5625	270	-	3715	7.6	14200	350	25400	3.0
% REJECTION	85	90	-	60	81	98	>99	>99	>99	>99	>99	91	-	98	>96	96	92
							Dow Cellulose Triacetate Hollow Fiber Membrane[3]										
FEED	-	70	<0.12	3	1.0	2.5	42	55	25	30	30	660	7.8	5000	40	5000	0.15
PRODUCT	-	20	<0.04	1	0.13	0.3	12	30	0	0	0	90	7.5	610	<5	500	0.10
REJECT	-	280	<0.18	8	6.1	13.0	155	105	75	-	-	2900	7.9	18000	200	26400	8.28
% REJECTION	-	71	-	67	87	88	71	45	>99	>99	99	86	-	88	>88	90	31

NOTES:
1. Hygas Run 79 quench water treated through activated carbon adsorption, mg/L except as noted. Data show results of large composite sample analysis after approximately 60 hours of testing.
2. Reverse osmosis tests conducted at 400 psig and 75 percent conversion.
3. Reverse osmosis tests conducted at 280-350 psig and 75 percent conversion.

following bench-scale treatment train processing HYGAS process condensate: ammonia stripping, activated sludge (SRT = 40 days), lime-soda softening and GAC carbon filtration.

Forced Evaporation

Forced evaporation is proposed for reverse osmosis centrate treatment to recover additional clean water and reject a highly concentrated salt brine fraction for disposal. Due to lower energy consumption and relative simplicity, the vapour mechanical recompression evaporation process has been chosen over multi-effect flash evaporation systems for proposed coal conversion plants and the one full-scale operating system recently installed at SASOL II. The system is used to treat cooling tower blowdown and spent regenerant wastes from the ion exchange units. A schematic is shown in Figure 5.11. Operational data for this system were unavailable.

Freeze Concentration

Freeze concentration has been proposed as a primary treatment/phenol and ammonia recovery method. It has also been proposed for tertiary dissolved solids removal. However, the technology has not yet been proven at commercial scale. Freeze concentration should, in theory, consume much less energy than forced evaporation due to the reduced energy input required to effect the phase change from liquid to solid compared to liquid to vapour.

Some very general information has been published on the operation and performance of this process with gasifier quench condensate. Concentrates of up to 15 to 20 percent inorganics and up to 35 percent organics were reported in a pilot-scale test. However, the detailed performance data

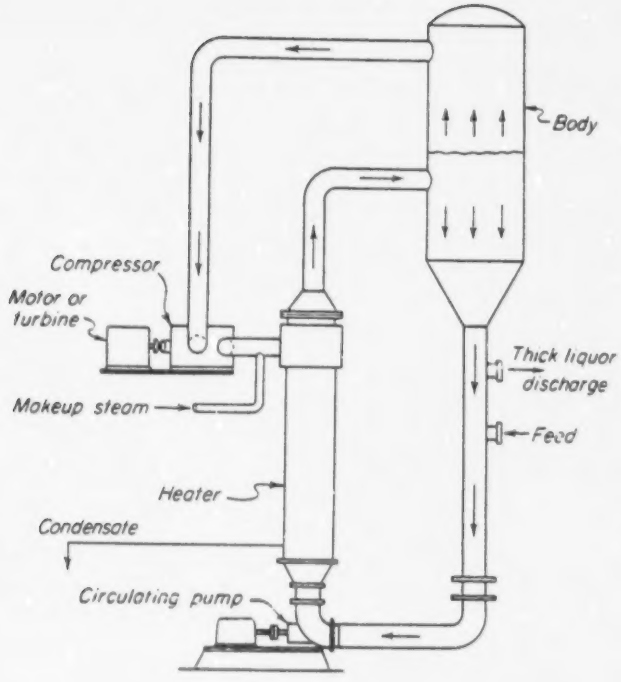


FIGURE 5-11 VAPOUR RECOMPRESSION (MECHANICAL) EVAPORATION

were considered proprietary information[45]. Due to the potential for removal of trace level organics from tertiary effluents and its reported ability to remove ammonia and phenol effectively in a single-stage treating raw process condensates, freeze concentration process commercial development should be followed closely.

Ion Exchange

At SASOL II, anion exchangers are used to reduce the dissolved inorganic salts concentration in the wastewater as the final step prior to introduction to the cooling tower. Carbon adsorption treatment upstream of this unit apparently provides an adequate safeguard from organic substances despite the fact that the carbon adsorption effluent is stated to contain 50 mg/L COD. SASOL II is the only coal conversion facility in which ion exchange has been proposed to be utilized. Some performance data and operating problems encountered are given in Appendix B.

Carbon Adsorption

Granular activated carbon (GAC filter) adsorption is used at SASOL II to remove residual organics from the effluent before ion exchange. Data on specific organic species removal or removal of heavy metal ions were unavailable. Carbon losses are reportedly high due to persistent problems encountered in the regeneration stage (see Appendix B).

Carbon adsorption has also been used as a secondary treatment step on diluted (approximately 100:1) and equalized H-Coal Catlettsburg pilot plant sour water.

Activated carbon adsorption efficiency on this waste was reported as:[32].

PARAMETER	% REMOVAL
COD	85
Phenol	99.9
Oil & Grease	85
Ammonia	10
TSS	90

The exact characteristics of the carbon and the design and operating mode of the filters were not reported. The pilot plant was processing Kentucky No. 9 coal in the syncrude mode during the tests.

Performance comparisons between GAC column treatment of activated sludge effluent and activated sludge/powdered activated carbon adsorption treatment have been made at the bench-scale for treatment of HYGAS Process condensate[44]. The results are shown in Table 5-4, which indicates the superiority, in this case, of GAC filtration over PAC addition in terms of removal of all parameters reported except effluent colour.

TABLE 5-4 COMPARISON OF POWDERED AND GRANULAR ACTIVATED CARBON TREATMENT (44)

PARAMETER mg/L	GRANULAR ACTIVATED CARBON		POWDERED ACTIVATED CARBON	
			Biox Eff., B=20d	
	Biox. Eff. Sample (Reactor A, B_C =20d)	GAC Treated Biox Eff.	Reactor C PAC=1500 mg/L	Reactor D PAC=5000
BOD	27	7	32	16
COD	820	270	370	280
Phenolics	0.89	<0.05	0.71	0.26
Organic-N	23	12	5.2	4.3
SCN^-	4.4	0.8	2.5	1.9
Total Freon Extractable Matl.	16	9.5	-	5
Color (Pt-Co units)	3000	1250	2100	600

5.2. Biological Treatment

5.2.1. Activated Sludge Process

The activated sludge process has been successful in the treatment of coal coking and petroleum refinery process wastewaters. However, coal conversion processes other than high-temperature entrained flow gasifiers tend to generate quench condensate streams containing much higher levels of bio-inhibitory and refractory polar organic species[46]. Fundamental research studies at the lab and bench-scale with both synthetic and actual coal conversion process wastewaters have, therefore, been directed at determining the effects of these compounds on the performance of biological treatment systems and means to minimize their impact.

A systematic and comprehensive program being conducted at Carnegie Mellon University to evaluate coal conversion wastewater management options is currently in its sixth year of operation. A substantial amount of bench-scale data on the performance of activated sludge treatment has been published[44,47,48,49]. A review of results from bench-scale studies with several different coal conversion process condensates indicates the following:

1) Process condensates are non-biodegradable unless the bio-oxidation process is preceded by a pretreatment stage, typically ammonia stripping and phenol extraction. Without pretreatment, substantial dilution is necessary to render the wastewater biodegradable[49].

2) Ammonia is readily converted to nitrate when the mean cell residence time (SRT) in the system is maintained at 40 days or greater[44].

3) In almost all cases, 10 to 25 percent of the organic load to the activated sludge system has been bio-refractory. Trihydric phenols (usually in a polymerized state), alkylated benzenes, PAH's and high molecular weight carboxylic acids generated by phenolic compound degradation have been identified as bio-refractory compounds[46].

4) There were no data available on the response of bench-scale systems to programmed upsets to critical operating parameters such as pH, temperature, organic loading, or specific toxic chemical loading.

5) Given adequate feed pretreatment and/or dilution and stable operating conditions, up to 90 percent of the influent COD, up to 99 percent of the BOD, 99 percent of total phenols, and up to 96 percent of thiocyanate can be removed from coal conversion process condensates by the activated sludge process operating at a 20 to 40 days SRT[34].

6) The SASOL II biological treatment system is operated in the pre-denitrification/nitrification mode. Information on the process is given in Appendix B. Denitrification, either in a separate stage or linked by recycle with nitrification, has not been addressed to date in North American bench-scale studies conducted with coal conversion wastewaters.

7) In a very recent study, it was reported that, although solvent extraction with MIBK removed a higher proportion of total phenol from the wastewater studies,

diisopropyl ether solvent was able to produce an extracted effluent resulting in a lower effluent COD in the subsequent bio-oxidation unit[50]. It was suggested that diisopropyl ether removed a larger amount of bio-refractory compounds than MIBK. Very high solvent-to-feed ratios were used. Diisopropyl ether and MIBK are the solvents utilized in the Phenolsolvan and Chem-Pro phenol recovery processes respectively (see Section 5.1.3.).

Table 5-5 shows the performance of a bench-scale activated sludge unit, and the effect of powdered activated carbon (PAC) addition, on the standard process operating and influent/effluent variables for ammonia-stripped and diluted process condensate from the pilot-scale Grand Forks Energy Technology Centre fixed-bed slagging gasifier. Table 5-6 shows the removal efficiency selected heavy metals by the activated sludge and PAC-assisted activated sludge process during the above-mentioned experiments.

5.2.2. Activated Sludge/Powdered Activated Carbon Process

The activated sludge/powdered activated carbon (PAC) process is currently being promoted by Zimpro Inc. as the commercialized PACT process. The extent of the patent rights over PAC addition to the activated sludge process is not currently known since these rights have not, to date, been challenged.

The results of PAC addition to full-scale activated sludge units at 14 different petroleum refineries has been reported[51]. Priority pollutant removal in a full-scale PACT process used to treat industrial organic wastewaters has also been reported[52]. These data are shown in Table 5-7.

TABLE 5-5

AVERAGE STEADY STATE PERFORMANCE DATA FOR [44]

BIOLOGICAL OXIDATION WITH THE ADDITION OF POWDERED ACTIVATED CARBON

33% STRENGTH STRIPPED GFETC GASIFIER WASTEWATER, θ_c = 40 DAYS

OPERATING DATA	REACTOR A	REACTOR B	REACTOR C	REACTOR D
Dates	7/28-9/20/79	7/28-9/20/79	7/28-9/20/79	7/28-9/20/79
Aeration Chamber, Volume, l	5.2	5.9	5.2	5.2
Clarifier Chamber, Volume, l	0.8	0.5	0.8	0.8
Powdered Activated Carbon Equilibrium Concentration, mg/L	0	500	1500	5000
Flow, l/d	0.49	0.45	0.51	0.46
Hydraulic Residence Time, d	10.5	13.1	10.2	11.4
MLSS, mg/L	2500	3020	4290	7550
MLVSS, mg/L	2140	2700	3870	6920
Dissolved Oxygen, mg/L	>3.0	>3.0	>3.0	>3.0
pH range, units	7.0-7.5	7.0-7.5	7.0-7.5	7.0-7.5
Zone Settling Velocity, ft/hr	10.8	11.1	15.5	8.7
Sludge Volume Index, mL/g MLSS	71	64	47	34
O_2 Uptake Rate, Day^{-1}	0.23	-	-	-
O_2 Utilization Rate, mg O_2/min	0.22	0.18	0.27	0.25
COD Rem. Rate, day^{-1}	0.24	-	-	-

PARAMETER (mg/L)	INFLUENT	EFFLUENT CHARACTERISTICS			
BOD	3780	27	14	12	6
COD	6070	710	590	460	285
Phenolics	1300	0.54	0.38	0.29	0.14
NH_3-N	145	3.7	2.8	2.3	1.2
Organic-N	33	8.7	7.6	6.6	4.9
NO_3^--N	<2	310	320	330	390
SCN^-	45	5.4	4.0	3.5	2.2
Color, Pt-Co Units	-	2500	2250	2000	750

TABLE 5-6

METAL REDUCTION THROUGH

BIOLOGICAL AND PAC TREATMENT

θ_C = 20 DAYS, 33% GFETC STRIPPED WASTEWATER (44)

Element	Influent	EFFLUENT			
		Reactor A, PAC = 0 mg/L		Reactor D, PAC = 5000 mg/L	
	mg/L	mg/L	% Removal	mg/L	% Removal
Zn	0.954	0.33	65	0.096	90
B	2.95	1.01	66	0.986	67
Fe	3.74	3.13	15	0.622	83
Mg	3.75	3.01	20	2.13	43
V	0.059	0.027	54	0.012	80
Cr	0.087	0.074	15	<0.026	>70

TABLE 5-7 PRIORITY POLLUTANT REMOVAL BY CHAMBERS WORKS PLANT[52]

Compound	Concentration ppb Feed	PACT Effluent	Average Removal
Benzene	105	0.9	98
Carbon Tetrachloride	94	1.4	95
Chlorobenzene	1,720	30	98
Chloroethane	280	12	94
Chloroform	201	21	81
Ethylbenzene	41	1.7	94
Methyl Chloride	1,770	nil	>99
Tetrachloroethylene	24	1.7	93
Toluene	519	4.7	99
1,1,1-Trichloroethane	13	0.6	89
Trichloroethylene	41	1.9	94
Trichlorofluoromethane	155	3.0	95
1,2-Dichlorobenzene	259	120	44
2,4-Dinitrotoluene	1,900	243	65
2,6-Dinitrotoluene	1,640	575	64
Nitrobenzene	454	2	>99
1,2,4-Trichlorobenzene	523	169	66
2-Chlorophenol	11	0.6	95
2,4-Dinitrophenol	161	5.0	98
4-Nitrophenol	1,020	10	97
Phenol	489	38	94

To date, evaluation of PAC-assisted activated sludge treatment with coal conversion wastewaters has been conducted at the bench-scale only. Tables 5-5 and 5-6 show the performance of PAC-assisted activated sludge treatment at varying equilibrium PAC concentrations in the mixed liquor for treatment of GFETC gasifier quench condensate following ammonia stripping and dilution. The performance of a bench-scale Zimpro PACT unit on ammonia-stripped and MIBK solvent extracted (Chem-Pro bench-scale unit) H-Coal pilot plant sour water is shown in Table 4-42.

A review of bench-scale studies on coal conversion wastewater treatment by the PAC-assisted activated sludge process indicates the following:

1) Higher removal of BOD, COD, TOC, total phenol, ammonia and organic nitrogen, thiocyanate, and colour is observed in PAC-assisted systems compared to unassisted activated sludge systems (see Table 5-5).

2) The effect of PAC-addition on the response to programmed upsets in influent variables and process operating variable has not, to date, been investigated. The PACT process is reported to dampen shock loads in application to oil refinery wastewaters[51].

3) PAC-assisted activated sludge treatment is reported to enhance removal of high molecular weight polar organic species and PAH compounds[53].

4) Nitrification appears to be enhanced by PAC addition (see Table 5-5).

5) Secondary beneficial effects to overall operation, including reduced tendency of foaming in aeration

basins and improved sludge settleability, have been reported[53].

6) From the results of the one evaluation conducted to date, GAC filtration of activated sludge effluent appears to generate a higher quality effluent than PAC-assisted activated sludge treatment for PAC levels in the mixed liquor up to 5,000 mg/L[44] (see Section 5.1.5., Table 5-4). Economic considerations involved in the comparison of PAC-assisted activated sludge to GAC filtration of activated sludge effluent are given in Reference 54.

5.3. Water Reuse Considerations

The need for water reuse in a coal conversion facility arises primarily from consideration of national, provincial, and local aqueous effluent discharge criteria expected to be in effect when the plant is brought on stream. A second consideration is fresh water availability. Fresh water availability is becoming more and more an issue in Western Canada where large-scale coal and other fossil-fuel resource development has grown significantly in the past decade.

That more stringent discharge criteria will be brought into effect over the next 5 to 10 years in North America is virtually certain. The magnitude of the changes may depend largely upon the emergence of relatively inexpensive methods for trace pollutant analysis. In the U.S., the Clean Water Act stipulates that there should be no further discharge of pollutants to surface or groundwater by 1985. While this may be very difficult to achieve, it clearly indicates that, in future, it may be more economical to reuse wastewaters in the plant than to incur the costs of sophisticated treatment before discharge under potentially very stringent and comprehensive regulations.

Due to the above factors, it appears that pioneer coal conversion plants in North America will incorporate at least partial reuse of the wastewater generated in the plant (see Appendix A). The conceptual plant designs, similar to the SASOL II and III operations, propose the reuse of treated process wastewater in wet cooling towers where the stream is ultimately discharged as evaporation. With the exception of the Texaco process, recycling of fully-treated wastewater to the coal conversion reactor or other plant processes (other than product quench systems) is not feasible. The effect of reuse of wastewater from the Texaco process as make-up to the coal slurry preparation stage and

specifically the potential for trace element build-up in the system, has not been addressed in the available literature[55].

Achieving a stable water balance as SASOL II has been difficult. It appears that the plant has been a net producer of water unsuitable for reuse despite the fact that the plant is located in a semi-arid region of large net negative precipitation where annual evaporation exceeds annual precipitation. Also, the process wastewater treatment system has undergone considerable modification since plant start-up early in 1981 (see Appendix B). In the one available North American study in which a complete bench-scale treatment train designed to provide reusable water from process condensate wastewater was evaluated, it was shown that high-quality treated water suitable for reuse as boiler feed water make-up could be produced[44]. However, the processes were operated under ideal conditions and no programmed process upsets were introduced.

Experience gained in the thermal electric power generation sector in the U.S. (approximately 30 plants in U.S. operating with zero-water discharge schemes[56]) has only limited applicability to coal conversion systems. Design criteria are needed, both for individual control processes and their implementation in treatment trains processing coal conversion wastewaters for reuse, such that realistic cost projections can be provided to both regulatory and industrial planners. Evaluation and development of control processes, such as wet air oxidation or freeze concentration, which possess the potential to eliminate large fractions of both organic and inorganic pollutants in the wastewater in one unit operation should be pursued as a means to reduce the complexity of treatment trains such as those now proposed for full-scale coal conversion plants.

6. COAL CONVERSION WASTEWATER TREATABILITY STUDY

6.1. Influence of Phenolic Compounds on Wastewater Treatability

Phenolic compounds comprise the family of aromatic organic chemicals containing one or more hydroxyl groups. Several phenolic compounds potentially present in many coal conversion process raw product quench liquors are shown in Table 6-1 where they are classified according to the number of attached hydroxyl groups.

Fillo and Massey[57] have proposed a pathway for phenolic compound production in a generic coal gasification model, presented in Figure 6-1. In this model, it is presumed that phenols are formed exclusively during coal devolatilization and that subsequent dealkylation and aromatic ring decomposition reactions are necessary to produce the desired non-aromatic hydrocarbon products.

In general, the amount and composition of phenolic compounds in a coal conversion process wastewater influences, to a large extent, the overall mode of wastewater treatment. An examination of Table 4-26, section 4.3.1., reveals that 88 percent of the theoretical COD and TOD levels in SASOL I wastewater is contributed by the phenolic species content. A similar proportion of the COD and TOC level in the H-Coal direct liquefaction process is contributed by phenolic species after correction for sulphides oxidation[32].

Most coal conversion processes, including those considered in this report, generate a highly buffered process wastewater of high pH, due mainly to carbon dioxide and ammonia absorption in the raw product quenching stage. Physical/chemical treatment methods involving chemical addition to form insoluble phenolates or carboxylates are uneconomical where these contaminants are highly concentrated or the wastewater volume is large. Thus, a

TABLE 6-1 PHENOLIC COMPOUNDS PREVALENT IN COAL CONVERSION QUENCH LIQUORS

NAME	TYPE	SOLUBILITY[58] (g/100 g H_2O at 25°C)
Phenol	Monohydric	9.3
O,M,P- Cresol (Methyl Phenols)	Monohydric	2.3-2.6
Xylenols (Dimethyl Phenols)	Monohydric	soluble to slightly[a] soluble
Catechol	Dihydric	45
Resorcinol	Dihydric	128
Hydroquinone	Dihydric	8
Phloroglucinol	Trihydric	very soluble[a]
Pyrogallol	Trihydric	very soluble
Hydroxyquinol	Trihydric	very soluble

a - no quantitative definition of these terms are given.

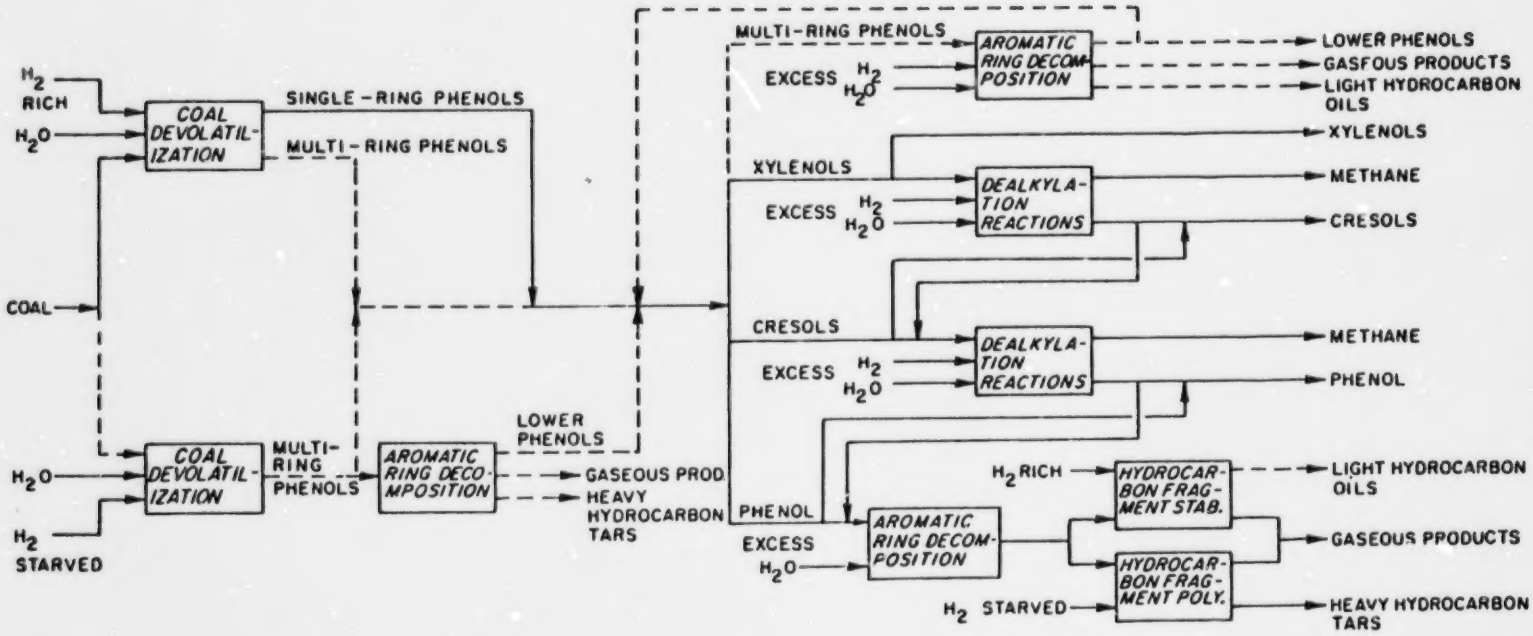


FIGURE 6-1 **Pattern of phenolic compound production in coal gasification processing.**(57)

biological treatment method, with or without pretreatment stages, is usually considered[27].

Bio-oxidation treatment of coal conversion process wastewaters containing phenolic compounds is hampered by the toxic or inhibitory effects of the phenol species due either to high level substrate inhibition or direct toxicity/inhibition by certain species at low levels. Polyhydric phenols are believed to be bio-inhibitory at low levels[46], however, no direct evidence is available in the literature.

A comparison of the biodegradability of a coke plant wastewater with several coal conversion process wastewaters is shown in Table 6-2. The data show that the coal conversion wastewaters, with the exception of the Hygas process, required dilution to the range of 22 to 40 percent strength to achieve biodegradable influent COD and phenolics levels where a biomass acclimatized to coal coking waste was used. In addition, the refractory levels of COD in the bio-oxidation process effluents were, in most cases, significantly greater than that observed for the coke plant waste. The maximum influent level of phenolics, which were subsequently bio-oxidized was 1,730 mg/L, however, the levels of individual species were not reported.

In a full-scale plant, it is unlikely that quench waters containing high levels of phenolic compounds would be diluted by relatively clean waters from the plant or additional fresh water since it would significantly enlarge the volume of contaminated waste for treatment and increase the overall fresh water requirement of the plant. An alternate approach is to employ solvent extraction pretreatment for removal of phenolic and other toxic or inhibitory organic compounds from highly concentrated wastewaters generated by the plant prior to biological treatment. This approach is used at SASOL I and II to recover pure phenolic species by-products from process wastewater to (see Table 4-26, Section 4.3.1.). The Phenolsolvan extraction process of SASOL I

TABLE 6-2 COMPARATIVE PERFORMANCE DATA FOR BIOLOGICAL TREATMENT OF COAL COKING AND COAL CONVERSION EFFLUENTS[49]

PROCESS	WASTEWATER SOURCE	CHARACTERIZATION, mg/L							
		COD	BOD	PHENOLICS	SCN^-	NH_3-N	ORG-N	NO_3^--N	TOC
Coke Plant[a]	Ammonia still effluent	3900-4600	1700-2800	750-1000	280-510	35-92	21-27	<1	-
	Biox effluent	300-410	5-15	0.25-1.4	3-36	23-163	4-8	2-154	-
GFETC[b]	Raw process effluent	21000-30000	-	3500-6500	80-200	4000-7500	70-140	<2	-
	Pretreated biox influent	5380-7130	3000-6700	1090-1730	14-27	130-180	41-45	<2	-
	Biox effluent	1110-1340	75-230	0.6-1.6	1-3	14-54	17-21	90-280	-
Hygas[c]	Raw process effluent	3400-5300	2980	600-900	17-45	2600-4600	-	-	-
	Pretreated biox influent	3540-4190	2570-3090	620-940	12-24	136-148	10	<2-4	-
	Biox effluent	660-890	270-450	0.1-1.9	2-4	87-122	1-8	<2-4	-
Synthane[d]	Raw process effluent	22000	-	3000	31	9500	-	-	9090
	Pretreated biox influent	1250-5690	-	175-1205	-	500	-	-	500-1960
	Biox effluent	390-2030	-	<1.0-2.5	-	-	-	-	150-850
MERC[e]	Raw Process Effluent	-	-	-	-	-	-	-	-
	Pretreated biox influent	4800	2290	920	-	250	-	-	2290
	Biox effluent	820-1600	80-180	2.5-7.7	-	190-220	-	-	250-480
H-Coal[f]	Raw process effluent	88600	52700	6800	-	14400	51	-	-
	Pretreated biox influent	3070-4180	1890-2600	750-1450	-	68-140	10-24	-	-
	Biox effluent	310-380	24-36	0.3-9.7	-	40-140	5-13	-	-
Synthetic[g] Coal Conversion Wastewater	Raw waste	-	-	4650	-	1000	-	-	4600
	Pretreated influent	5710	3500	-	-	240	-	11	1600
	Biox effluent	190-1800	5-1000	-	-	210-250	-	2-7	45-200

a - Effluent BOD data are for a reactor showing a well nitrified effluent.
b - Raw gasifier effluent from Indian Head lignite. Pretreated for ammonia removal diluted to 33% strength.
c - Cyclone and quench effluents from Illinois subbituminous. Pretreated for ammonia removal, no dilution.
d - By-product water from Montana Rosebud subbituminous. Pretreated to ammonia removal and diluted to 5 to 6% and 25%.
e - Pretreated for ammonia removal and diluted to 36 to 40% strength. These data are from test series c with producer Run 90 wastewater.
f - Foul water from coal liquefaction. Pretreated for sulfide and ammonia removal and diluted to 22% strength.
g - Pretreated by dilution to 25% strength.

and II utilizes a recyclable high-cost solvent in amounts approaching the volume of the treated wastewater plus a solvent recovery distillation stage (see Section 5.1.4.) The unique market conditions in South Africa support the cost of extraction and additional costs incurred to separate the various phenolics in the by-product stream to useful pure components. In Canada, such an approach may not be feasible since the demand for by-product phenols is currently being met by the petroleum, tar sands, and coal coking industries. In addition, the costs of separating phenol and other phenolics from the complex mixtures generated in processes such as Lurgi or H-Coal may render the method uneconomical relative to the conventional sources. In this case, it may be desirable to incinerate the total by-product phenols stream. This option will be examined at the Great Lakes Containment Project in North Dakota, currently under construction and scheduled for completion in 1987[61].

Laboratory studies, utilizing extraction pretreatment at very high solvent-to-feed ratios (S/F ratio) to reduce phenol levels by 90 percent or greater, have shown the beneficial effects of severe extraction on overall wastewater biodegradability, toxic compound removal and nitrification[48,52]. Little work, however, has been done to investigate the impact of reduced extraction severity (i.e. solvent-to-feed ratio 0.5) on subsequent biological treatment and overall treatment economics. Such a scheme would involve the effective coupling of solvent extraction and biological treatment steps into an optimized operation to destroy organic contaminants in the wastewater while significantly reducing the volume of by-product phenols requiring further handling. It should be noted that the use of a PAC-assisted biological treatment system in conjunction with solvent extraction would not necessarily reduce the extraction severity required to render the waste biodegradable since polyhydric phenolic compounds or other highly soluble bio-inhibitory compounds may not effectively adsorb on activated carbon[60].

6.2. Coal Conversion Wastewater Treatability Study

As outlined in the preceding section, an information gap concerning minimum solvent extraction pretreatment coupled with biological treatment was identified. It was decided, therefore, to undertake a lab-scale screening evaluation of this mode of coal conversion wastewater treatment at Environment Canada's Wastewater Technology Centre. Since maximum ammonia levels are well-established for biological processes, the study focussed on bio-oxidation of total organic load and, in particular, phenolic species. A large sample of H-Coal pilot-plant combined sour water, produced from the processing of Illinois No. 6 coal to synthetic crude, was obtained for this work. A description of the sources of this wastewater is given in section 4.3.3. The sample had been ammonia-stripped at the plant site in a large free ammonia still. An analysis of this sample produced the data given in Table 6-3.

6.2.1. Extraction Solvent Selection

A review of the pertinent literature on solvent extraction of phenols from hydrocarbon process wastewaters was initiated. Two solvents were then selected for the treatability study based primarily on their high distribution coefficients for pure phenol and polyhydric phenols in aqueous systems. The distribution coefficient is defined as the concentration of, in this case, a phenolic compound in the solvent to that in the aqueous phase following sufficient contact of the solvent and aqueous phase to allow equilibrium to be attained. Table 6-4 shows a comparison of the distribution coefficients of phenolic species between water and several pure solvents. The data indicate the superiority of both MIBK and 2-octanone over various polar and non-polar solvents especially with regard to the highly water-soluble polyhydric phenols species. These solvents

TABLE 6-3

ANALYSIS OF AMMONIA-STRIPPED H-COAL COMBINED SOUR WATER FROM PROCESSING OF ILLINOIS NO. 6 COAL

PARAMETER	CONCENTRATION (mg/L) [a]	
TOC	10900	10800
COD	35600	37700
BOD_5 [b]	17700	19600
TKN	1000	1000
NH_3-N	870	890
NO_3-N	12	24
NO_2-N	-	-
Thiocyanate	<1	<1
Total Phenolics (UV Adsorption)	11900	
Total Phenolics (4AAP)	9200	

a - data from duplicate samples

b - average of 3 dilutions, values within 10% from BOD determinations on both samples

TABLE 6-3 (Continued)

TRACE ELEMENTS (ICP ANALYSIS)	UNFILTERED[a] (mg/L)		FILTERED[a] (mg/L)	
Aluminum	0.18	0.23	<0.01	<0.01
Barium	<0.005	<0.005	<0.005	<0.005
Beryllium	<0.005	<0.005	<0.005	<0.005
Boron	36.3	36.1	35.5	36.2
Cadmium	<0.01	<0.01	<0.01	<0.01
Calcium	4.51	4.38	2.84	2.84
Chromium	0.31	0.32	0.31	0.31
Cobalt	<0.05	<0.05	<0.05	<0.05
Copper	0.037	0.031	<0.008	<0.008
Iron	0.18	0.18	<0.01	<0.01
Magnesium	2.32	2.32	2.18	2.21
Manganese	<0.01	<0.01	<0.01	<0.01
Molybdenum	<0.3	<0.3	<0.3	<0.3
Nickel	<0.05	<0.05	<0.05	<0.05
Phosphorus	<0.6	<0.6	<0.6	<0.6
Potassium	<1.0	<1.0	<1.0	<1.0
Silica	1.00	1.00	1.00	1.00
Silver	<0.005	<0.005	<0.005	<0.005
Sodium	9.0	8.0	8.0	8.0
Strontium	0.045	0.045	0.033	0.044
Thorium	<0.01	<0.01	<0.01	<0.01
Titanium	<0.005	<0.005	<0.005	<0.005
Vanadium	<0.005	<0.005	<0.005	<0.005
Zinc	0.08	0.08	0.08	0.07
Zirconium	<0.05	<0.05	<0.05	<0.0

a - data from duplicate samples.

were therefore selected as the primary solvents to be evaluated in this work.

It is interesting to note that, in terms of distribution coefficients, di-isopropyl ether, used in the Phenolsolvan process, appears to be a less suitable solvent for phenol extraction than either of the solvents mentioned above. Due to the proprietary nature of the Phenolsolvan process, it is not possible to determine whether solvent additives, solvent recoverability, beneficial effects on downstream processes or a combination of the above factors is responsible for the choice of this solvent. However, in a paper published after the work presented here was completed, it was reported that, although solvent extraction with MIBK removed a higher proportion of total phenols from a coal conversion wastewater, diisopropyl ether was able to produce an extracted effluent resulting in a lower effluent COD in the subsequent bio-oxidation unit. It was suggested that diisopropyl ether removed more bio-refractory compounds than MIBK[50]. In both cases, however, a very high solvent-to-feed ratio was used. Thus, at low solvent-to-feed ratios, the emphasis on bio-inhibitory compound removal suggests the use of a solvent such as MIBK to render the waste biodegradable with minimum solvent requirements.

The performance of mixed-solvent systems was also evaluated. A low level of primary solvent was blended with an essentially non-polar light oil solvent, analogous to a process-derived light oil distillate fraction, to investigate the possibility of further reducing the amount of relatively expensive primary solvent through mixing with higher levels of a much cheaper, though less-effective, process-derived hydrocarbon solvent.

Since an H-Coal process-derived oil was not available due to its proprietary characteristics, Esso wash oil and kerosene

TABLE 6-4 DISTRIBUTION COEFFICIENTS AT HIGH DILUTION FOR VARIOUS PHENOLIC COMPOUNDS BETWEEN WATER AND SELECTED SOLVENTS[61]

	Monohydric Phenols				Polyhydric Phenols			
	Phenol	o-Cresol	m-Cresol	Xylenol	Catechol	Resorcinol	Pyrogullic Acid	Hydroxy-quinone
benzene	2.9,2.9, 2.3	12.1, 16	10	33	0.119	0.00045		
3-heptanone		136			10.8	13.3	2.2	4.8
di-isopropyl-ether	41.6, 40,32,7	28.3			16.0, 12.6,4.9	2.14		0.81
1-octanol	48,31, 40	89			13.0	9.9	1.4	3.5
n-butyl acetate	54,61,65, 71,48	220, 206	150,153	540	13.9,13, 10.6,13.2	9.0,9.9	1.8	7.2
methyl isobutyl ketone	115,110		260	814	20,15, 18.7	15.2,17.9	3.6	
2-octanone	110	303			15.0	22.2	2.9	8.4

were selected as background solvents in the mixed-solvent evaluation. Some preliminary work with these solvents led to the use of ESSO wash oil in the mixed-solvent evaluations reported here.

6.2.2. Experimental Procedure

Phase I

The treatability study was conducted in two phases after results from the initial work (Phase I) indicated a need for a refined approach which was then implemented in Phase II. Figure 6-2 presents a schematic description of the experimental procedure employed in Phase I. It is essentially a solvent screening study with the goal of determining minimum solvent extraction levels of selected solvent systems to render the H-Coal waste biodegradable.

The experimental procedure involved two separate stages - a solvent extraction step followed by a biodegradability evaluation. The solvent extraction step consisted of a single-stage batch experiment. Ammonia-stripped H-Coal sour water was contacted with a specified volume of solvent, as determined by the selected solvent-to-feed ratio, to give a 1-litre total batch volume in a 2-litre separatory funnel. Table 6-5 presents the solvent-to-feed ratios for the single and mixed solvents described in the previous section which were applied in the extraction performance experiments in Phase I. The wide range of solvent-to-feed ratios employed, reflected the fact that no prior studies had been conducted in the area of minimum extraction.

The solvent-wastewater system was brought to equilibrium by the procedure recommended by Mayhue[62] of 50 hand inversions of the separatory funnel in 1½ to 2 minutes. The organic and aqueous phases were then allowed to separate for

FIGURE 6-2 EXPERIMENTAL PROCEDURE FOR THE PRELIMINARY TREATABILITY STUDY - PHASE I

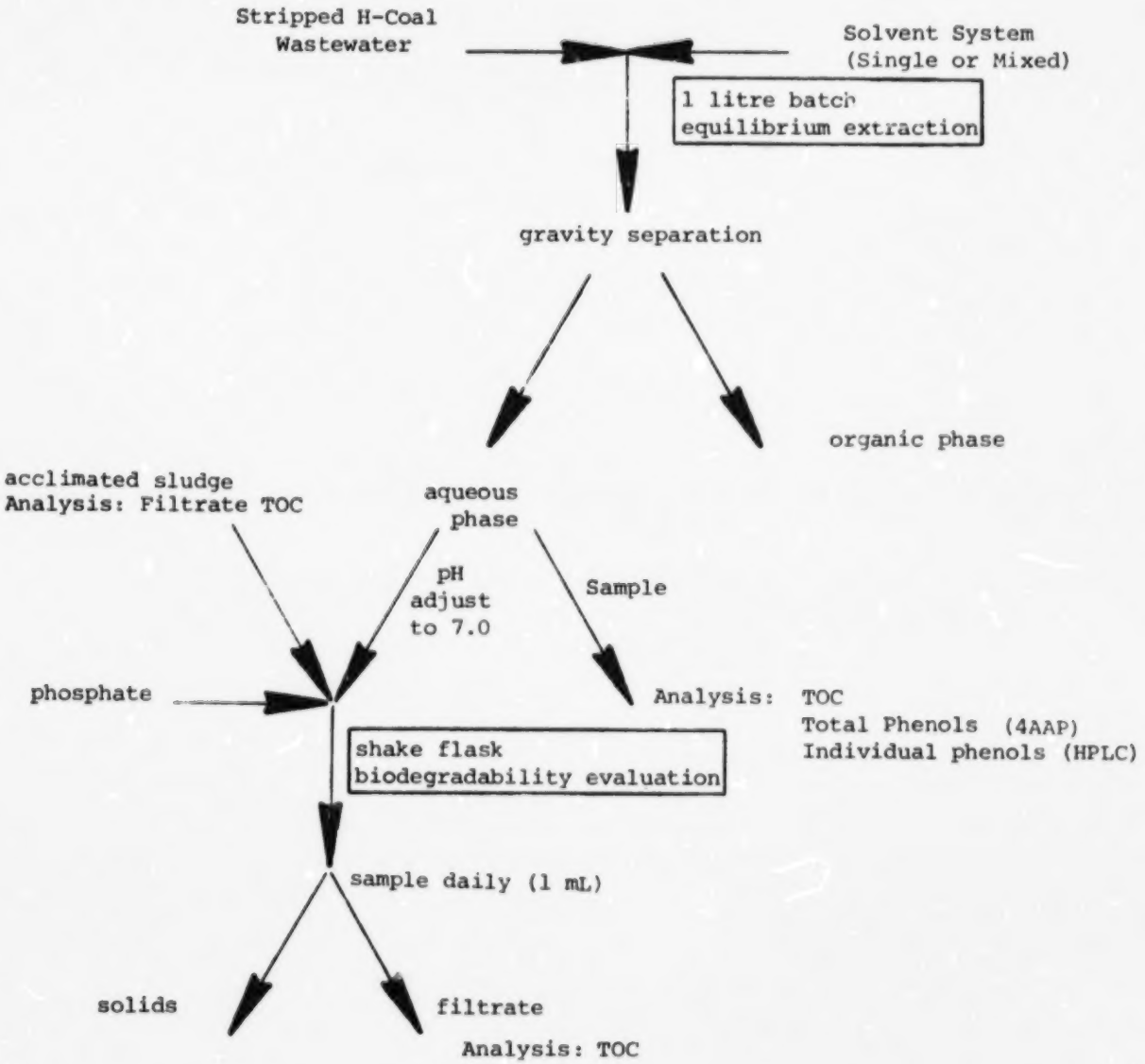


TABLE 6-5 SOLVENT-TO-FEED RATIOS EMPLOYED IN PHASE I BATCH EXTRACTION EXPERIMENTS

(Total: 24 Experiments)

SINGLE SOLVENT SYSTEMS					
SOLVENT	SOLVENT-TO-FEED RATIO				
MIBK	0.05	0.10	0.15	0.20	0.30
2-OCTANONE	0.05	0.10	0.15	0.20	0.30
KEROSENE	0.20	0.30	0.40		
LIGHT OIL (ESSO WASH OIL)	0.20	0.30	0.40		

MIXED SOLVENT SYSTEMS				
SOLVENT	SOLVENT-TO-FEED RATIO			
MIBK	0.025	0.025	0.05	0.05
LIGHT OIL	0.25	0.35	0.20	0.30
MIXED SOLVENT NO. 1	0.275	0.375	0.25	0.35
2-OCTANONE	0.025	0.025	0.025	0.05
LIGHT OIL	0.20	0.40	0.30	0.275
MIXED SOLVENT NO. 2	0.225	0.425	0.325	0.325

15 minutes. The aqueous phase was drawn off and samples taken for TOC determination, total phenolics determination by the 4AAP colorimetric and UV absorbance techniques and individual phenolics analysis by the HPLC technique.

In the biodegradability evaluation, a portion of the extracted sour water aqueous phase was contacted with an acclimated sludge in a shake flask system. To produce an acclimated sludge, a coking plant wastewater treatment activated sludge was supported on diluted ammonia-stripped H-Coal foul water. The wastewater feed was gradually converted from the coking plant ammonia still effluent to the diluted H-Coal foul water over a period of 8 days then supported on diluted foul water for a period of 36 days before the sludge was utilized in the biodegradability experiment.

Table 6-6 documents sludge viability over the duration of the acclimation period as indicated by oxygen uptake rate analyses. The data indicate that the sludge was respiring at a reduced level, although the respiration rate appeared to be increasing near the end of the acclimation period.

Before contact with the extracted wastewater, the sludge was left for a 24-hour period without feed addition to exhaust the major portion of TOC in the system and condition the biological solids. A filtered sample was taken for TOC determination immediately before introduction to the shake flask experiment to complete the TOC mass balance of the system. Phosphate was added to each shake flask experiment to the level of the theoretical demand of 1 percent of the BOD_5 for the unextracted ammonia-stripped H-Coal foul water, in this case 180 mg/L. Also, due to the high ammonia level in the wastewater, the pH of the aqueous phase was adjusted to 7.0 to ensure that the majority of the ammonia was in the non-toxic ionized (NH_4+) form. In each flask,

TABLE 6-6 SLUDGE ACCLIMATION SCHEDULE AND VIABILITY

Day	H-Coal Waste Feed Strength (%)	Suspended Solids (mg/l)	Oxygen Uptake Rate (mg/l/hr)
1	0	31100	
8	10	32900	50
13	10		40
14	10		35
15	10	27300	25.5
16	10		5.4
17	15		42
20	15		40
22	15		27
23	15		49.5
24	15		50
29	15	33200	43
41	15		45.5
43	15		60
44	0	32800	

400 ml of extracted wastewater were contacted with 100 ml of sludge. The wastewater had, therefore, an initial strength of 80 percent in the flasks.

A total of 24 extracted wastewater and one untreated wastewater shake flask experiments were carried out in Phase I. In addition, a control flask containing 500 ml of untreated wastewater only was run concurrently to evaluate TOC loss by volatilization during the experiment. The 25 biodegradability experiments were sampled immediately after sludge-wastewater contact, then at 24-hour intervals for TOC analysis. A 1 ml sample was required for each TOC determination. Samples for TOC analysis from the control flask were taken initially and at the end of the experiment. Biodegradability was determined from the TOC uptake curve over time corrected for losses due to volatilization.

Results from the Phase I solvent extraction and biodegradation work are given in Section 6.3.1. The results indicated that kerosene, light oil and the mixed solvents did not extract phenolic species effectively, even at the highest solvent-to-feed ratios evaluated. In addition, while both MIBK and 2-octanone were found to be highly effective in removing phenolic species from the waste, it appeared that high residual MIBK levels in the extracted phase may have inhibited the bio-oxidation stage. Lastly, the organic loading was not maintained constant in all of the bio-oxidation systems to allow for comparative analysis of the various solvent extraction pretreatment operations on subsequent bio-oxidation performance.

Based on the Phase I results, therefore, a second series of experiments were conducted to evaluate the remaining viable pretreatment options - minimum extraction by MIBK and 2-octanone.

Phase II

The experimental procedure followed was essentially the same as Phase I with the following alterations:

1) Following extraction, the aqueous phase was gently air-stripped and heat treated. The severity and duration required to remove residual solvent to below 50 mg/L was determined by in-house experiments utilizing Gas Chromatograph analysis to detect residual solvent in the aqueous phase by direct injection into the column. Heat treatment at 60°C for 1 hour removed the 2-octanone residual from the system while air stripping for 5 hours at the same temperature was required to remove residual MIBK. GC analysis also verified that loss of other low molecular weight species during the heat treatment of the aqueous phase was insignificant.

2) Following heat treatment and determination of the aqueous phase TOC, the extracted wastewaters were contacted with a predetermined amount of sludge such that an organic loading of 0.20 g TOC/g MLSS was established in each of the subsequent shake flask biodegradability experiments. The acclimated sludge from the Phase I biodegradation work, in which biodegradation of 2-octanone-extracted wastewater occurred, was utilized in the Phase II shake flask experiments.

3) An HPLC analyses of individual phenolic species was carried out at the conclusion of the Phase II shake flask experiments to determine the biodegradability of these compounds following solvent extraction of the ammonia-stripped H-Coal combined sour water.

A schematic representation of the Phase II experimental procedure is given in Figure 6-3. The experimental design criteria for the Phase II biodegradation study is shown in Table 6-7. A total of 11 shake flask experiments (including a control) were carried out in Phase II.

FIGURE 6-3 EXPERIMENTAL PROCEDURE FOR THE PRELIMINARY TREATABILITY STUDY - PHASE II

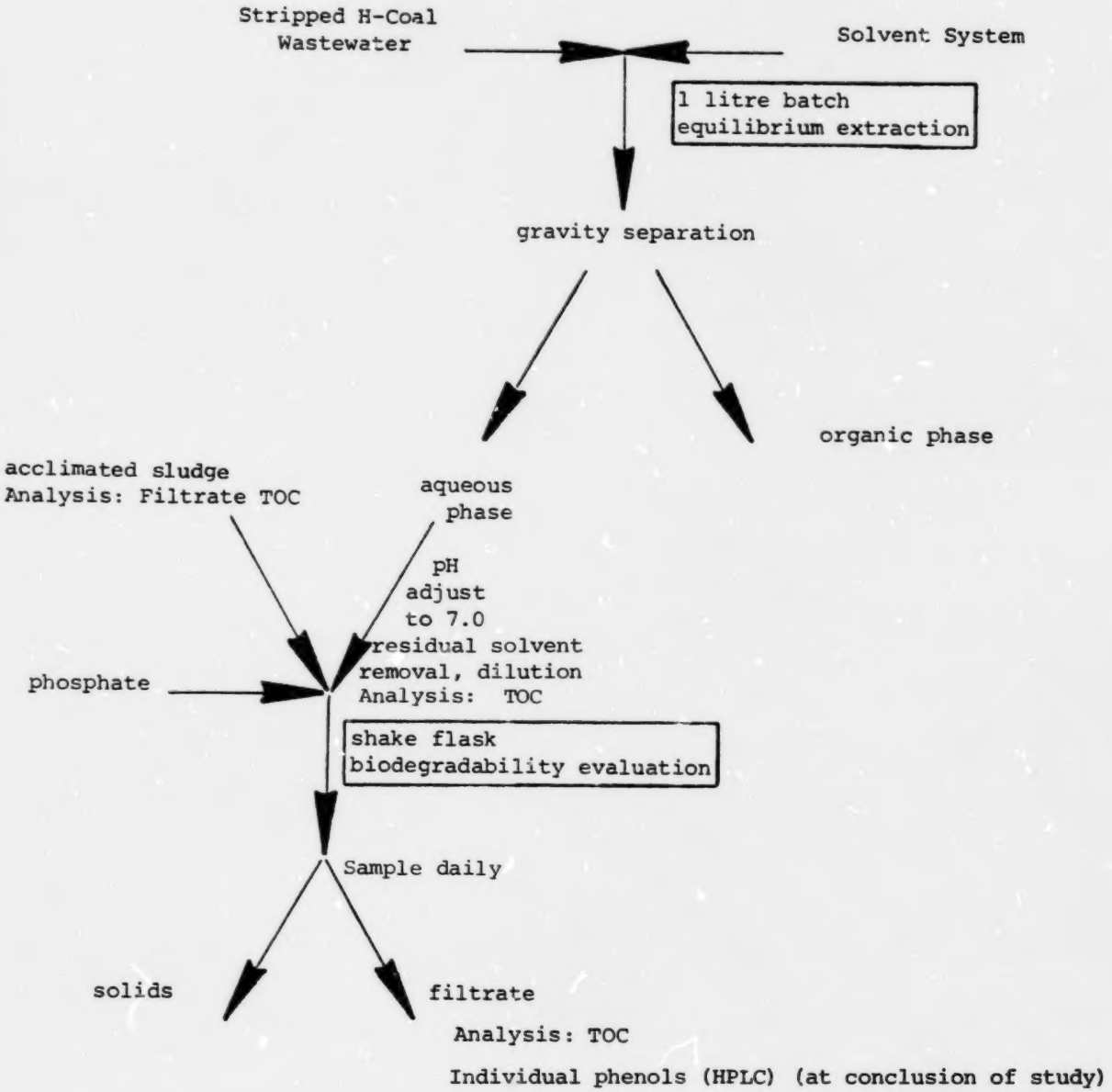


TABLE 6-7 PHASE II - TREATABILITY STUDY DESIGN FOR BATCH EXPERIMENTS

SOLVENT-TO-FEED RATIO	EXTRACTED WASTEWATER VOLUME (ml)	SLUDGE VOLUME[(a)] (ml)	% STRENGTH WASTEWATER IN SHAKE FLASK	ORGANIC LOADING IN SHAKE FLASK (g TOC/g MLS)
SOLVENT EXTRACTION WITH MIBK				
0.025	64	75	46	0.2
0.050	70	75	48	0.2
0.100	70	75	48	0.2
0.150	100	50	67	0.2
0.20	117	50	70	0.2
SOLVENT EXTRACTION WITH 2-OCTANONE				
0.025	81	75	52	0.2
0.050	111	75	60	0.2
0.100	97	50	66	0.2
0.150	104	50	68	0.2
0.200	56	50	76	0.2
CONTROL				
0	72	100	42	0.2

(a) Sludge concentration - 30,000 mg/L.

6.3. Experimental Results

6.3.1. Phase I Batch Solvent Extraction

In Phase I of the preliminary treatability study, 24 batch solvent extractions were carried out on ammonia-stripped H-Coal combined sour water from the Catlettsburg pilot-plant processing Illinois No. 6 coal. Samples from the extracted aqueous phase were then analyzed for remaining total phenols. These results are shown in Table 6-8 and Figure 6-4.

The data indicate that only MIBK and 2-octanone were effective in removing the total phenols fraction at relatively low solvent-to-feed ratios. The results of an HPLC analysis of individual phenolic species in the extracted aqueous phase from the batch extraction experiments are given in Table 6-9 and Figures 6-5 and 6-6. The data show that MIBK and 2-octanone possess very similar extraction efficiencies for phenol and cresols over the range of solvent-to-feed ratios used.

The polyhydric phenols - resorcinol, hydroquinone, and catechol - were not able to be detected by the HPLC technique. At the low pH (< 2) levels used to preserve the samples, polyhydric phenols may form polymeric substances which exist as colloidal suspensions in the aqueous phase. This was supported qualitatively by the observation of phase separation when concentrated acid was added, followed by the gradual formation of a miscible mixture. Resorcinol has previously been determined in H-Coal process sour water as shown in Table 4-41, Section 4.3.3.

It has been reported in the literature that polyhydric phenols are oxidized to polymeric colour precursors[46]. The presence of polyhydric phenols in the H-Coal sour water

TABLE 6-8 TOTAL PHENOLS REMAINING IN AQUEOUS PHASE AFTER SOLVENT EXTRACTION OF STRIPPED H-COAL SOUR WATER
(all values in mg/L)

Solvent	Solvent-to-Feed Ratio	Total Phenols in Aqueous Phase[a]	Pure Phenol in Aqueous Phase[b]
None	0	11900	6400
MIBK	0.05	4000	2500
"	0.10	2200	1500
"	0.15	1600	1000
"	0.20	1100	560
"	0.30	710	310
2-Octanone	0.05	3200	2500
"	0.10	1700	1100
"	0.15	1200	820
"	0.20	940	550
"	0.30	630	330
Light Oil	0.20	10000	6000
"	0.30	9100	5700
"	0.40	8600	5900
Kerosene	0.20	11000	6100
"	0.30	9900	6400
"	0.40	8900	6100
Light Oil & MIBK	0.20 & 0.05	8400	3600
" "	0.25 & 0.025	6000	3800
" "	0.30 & 0.05	3600	2400
" "	0.35 & 0.025	5300	3300
Light Oil & 2-Octanone	0.20 & 0.025	5500	3200
" "	0.30 & 0.025	3600	3800
" "	0.275 & 0.05	5500	2400
" "	0.40 & 0.025	5300	3600

(a) - UV absorbance

(b) - HPLC

FIGURE 6-4 TOTAL PHENOLS EXTRACTION EFFICIENCY OF VARIOUS SOLVENTS AND SOLVENT MIXTURES

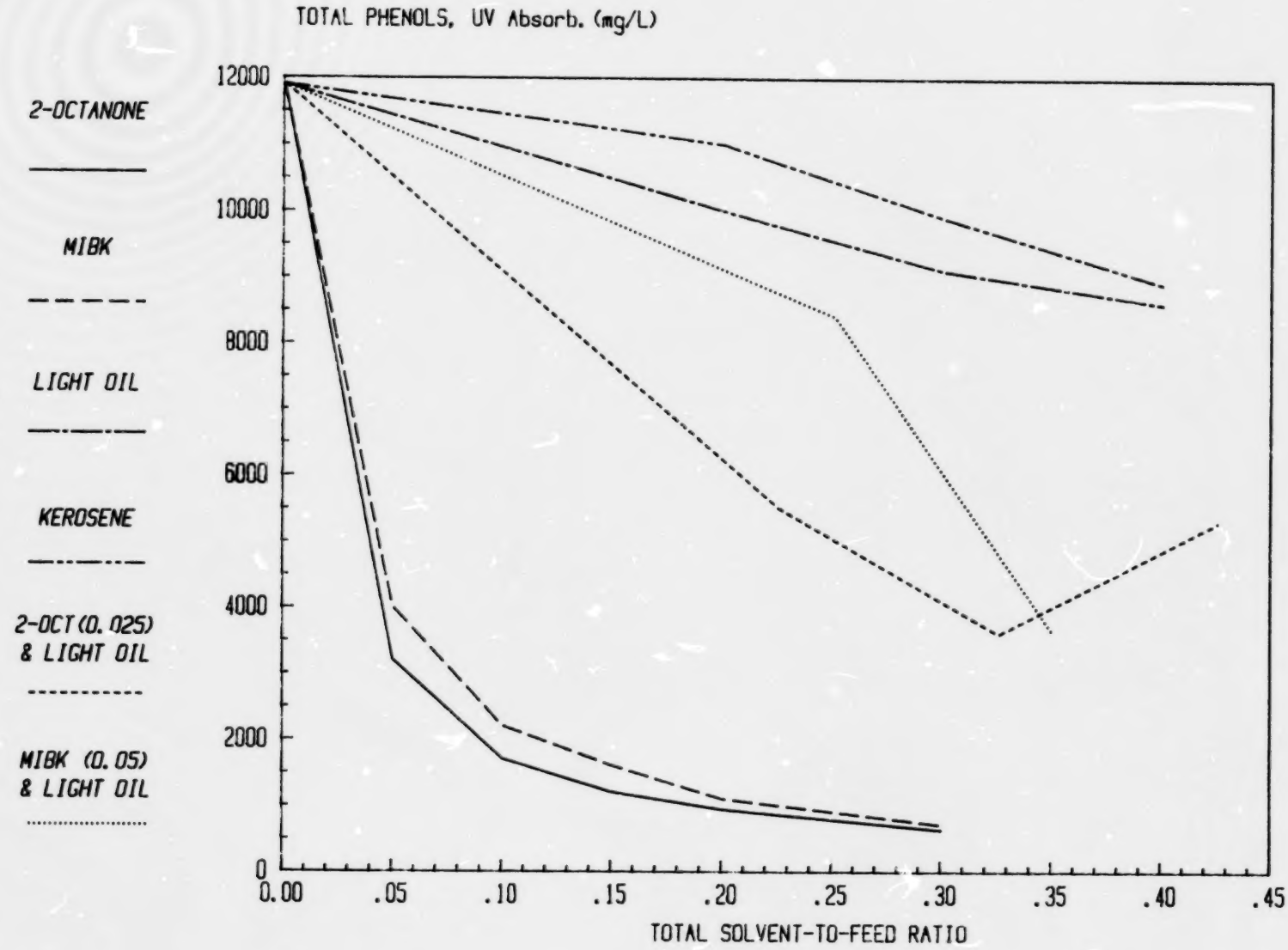


TABLE 6-9 PHENOLIC COMPOUNDS REMAINING IN AQUEOUS PHASE AFTER SOLVENT EXTRACTION OF STRIPPED H-COAL SOUR WATER.
(All values in mg/L, ND - not detected).

SOLVENT	Solvent-to Feed Ratio	Phenol	Meta & para Cresol	Ortho Cresol	3,4 Dimethyl Phenol	3,5 Dimethyl Phenol	Other Dimethyl Phenols.
None	0	6400	1600	1400	13	24	ND
MIBK	0.05	2500	290	190	ND	ND	ND
"	0.10	1500	150	96	ND	ND	ND
"	0.15	1000	99	ND	ND	ND	ND
"	0.20	560	48	ND	ND	ND	ND
"	0.30	310	25	ND	ND	ND	ND
2 - Octanone	0.05	2500	240	160	ND	ND	ND
"	0.10	1100	97	65	ND	ND	ND
"	0.15	820	67	44	ND	ND	ND
"	0.20	550	43	28	ND	ND	ND
"	0.30	330	27	13	ND	ND	ND
Light Oil	0.20	6000	1300	970	8.5	18	ND
"	0.30	5700	1100	790	9.6	ND	ND
"	0.40	5900	1000	710	8.0	9.8	ND
Kerosene	0.20	6100	1300	1000	9.2	15	ND
"	0.30	6400	1300	1000	10	15	ND
"	0.40	6100	1100	810	8.7	6.4	ND
Light Oil & MIBK	0.20 & 0.05	3600	370	210	ND	ND	ND
"	0.25 & 0.025	3800	470	410	ND	ND	ND
"	0.30 & 0.05	2400	240	140	ND	ND	ND
"	0.35 & 0.025	3300	370	280	ND	ND	ND
Light Oil & 2-Octanone	0.20 & 0.025	3200	380	240	ND	ND	ND
"	0.30 & 0.025	3800	430	260	ND	ND	ND
"	0.275 & 0.05	2400	220	140	ND	ND	ND
"	0.40 & 0.025	3600	390	250	ND	ND	ND

FIGURE 6-5

PHENOL SPECIES EXTRACTION EFFICIENCY OF 2-OCTANONE ON STRIPPED H-COAL SOUR WATER

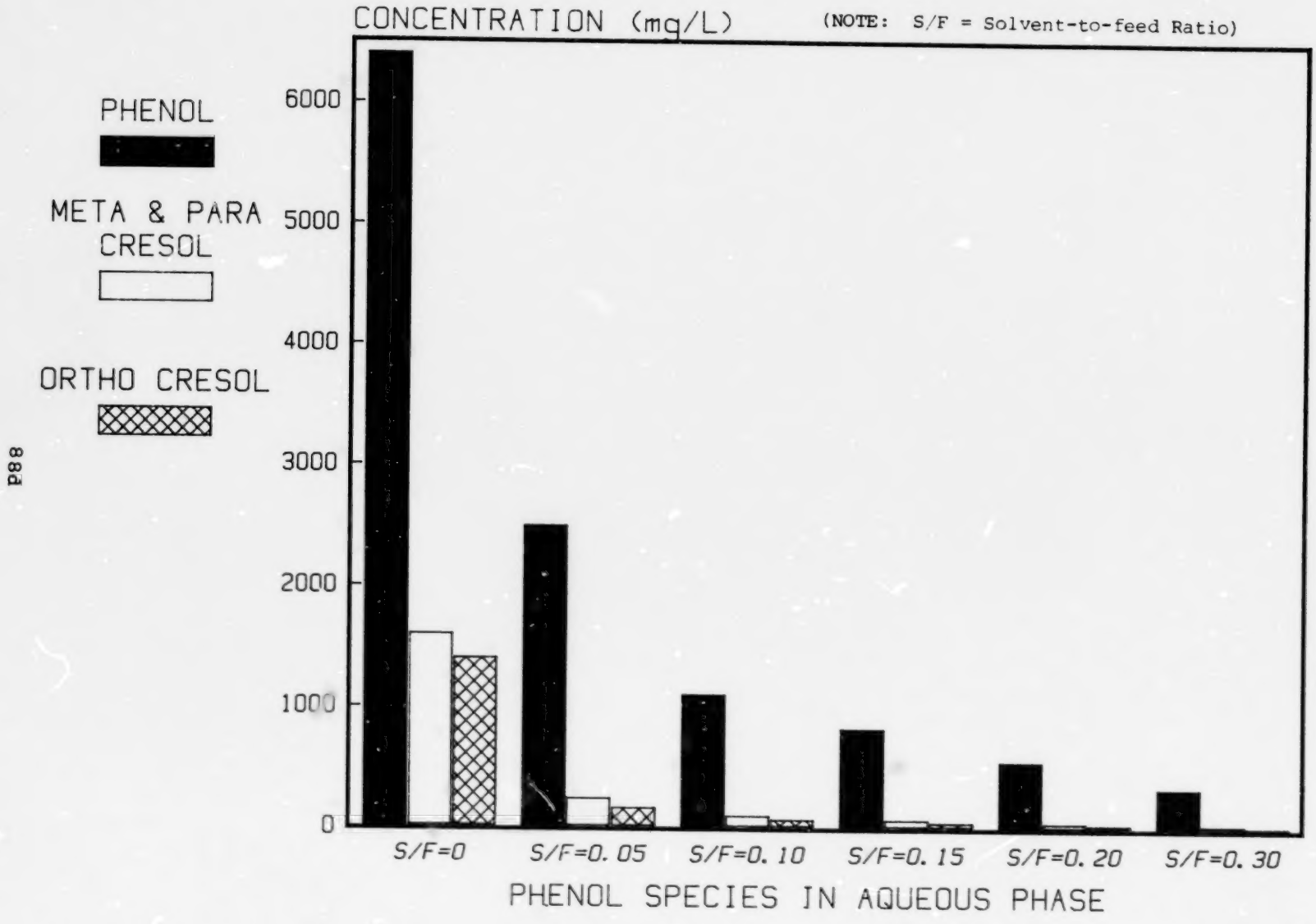


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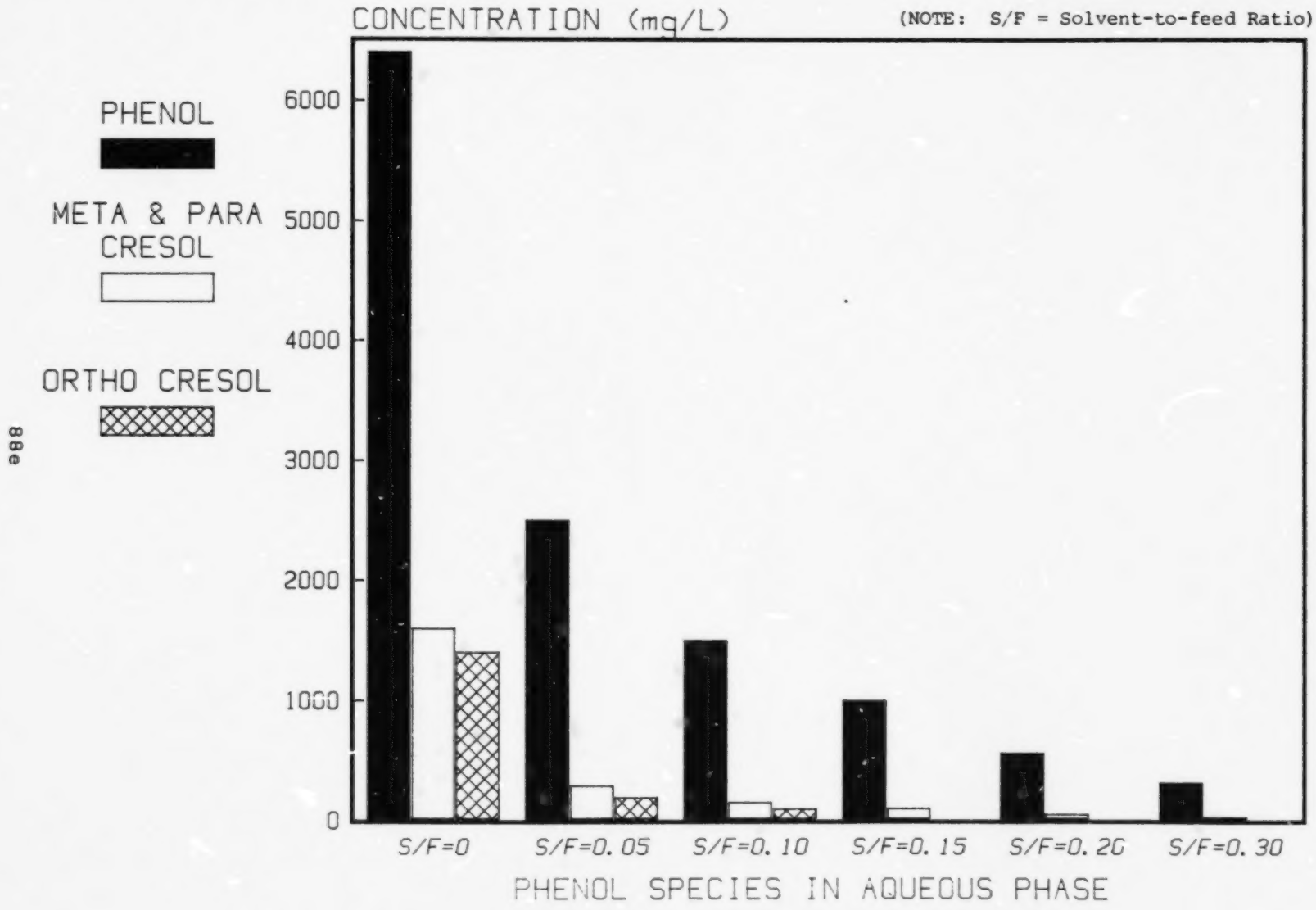
FIGURE 6-6

PHENOL SPECIES EXTRACTION EFFICIENCY OF MIBK ON STRIPPED H-COAL SOUR WATER



was supported qualitatively by the observation that the sour water was clear before contact with air, however, after contact with air for 2 - 3 minutes, the sour water changed to a virtually opaque brown colour. Solvent extraction by MIBK or 2-octanone at a solvent-to-feed ratio of 0.2 or greater was observed to extract a large amount of colour in the solvent phase, however, the aqueous fraction retained a deep brown colour following these extractions.

The Phase I extraction experiments utilizing the mixed solvents showed that the total phenol extraction efficiency of both MIBK and 2-octanone was reduced in the presence of the non-polar light oil solvent and that this negative effect increased with increasing amounts of light oil present (see Figure 6-4).

6.3.2. Shake Flask Biodegradability Study - Phase I

Following solvent extraction, the aqueous phase from each of 24 experiments and an unextracted sample of ammonia-stripped H-Coal sour water was contacted with an acclimated sludge in a 1-litre shake flask. Biodegradability of the aqueous phase was determined by TOC uptake over a period of 34 days. Only the 2-octanone-extracted wastewaters at solvent-to-feed ratios greater than 0.15 showed amenability to biological degradation. The biodegradation curves for the 2-octanone extracts, MIBK extracts and the control are shown in Figures 6-7 and 6-8.

A comparison of the data shown in Figure 6-8 with the MIBK extraction results shown in Table 6-8 suggests that residual solvent was present in the aqueous phase since the initial TOC levels in the shake flasks are greater than three times the TOC level contributed by the total phenols. Subsequent analysis of the MIBK aqueous extract by Gas Chromatograph confirmed that residual MIBK was present at its limit of

FIGURE 6-7 SHAKE FLASK BIODEGRADATION OF 2-OCTANONE-EXTRACTED H-COAL STRIPPED SOUR WATER - PHASE I

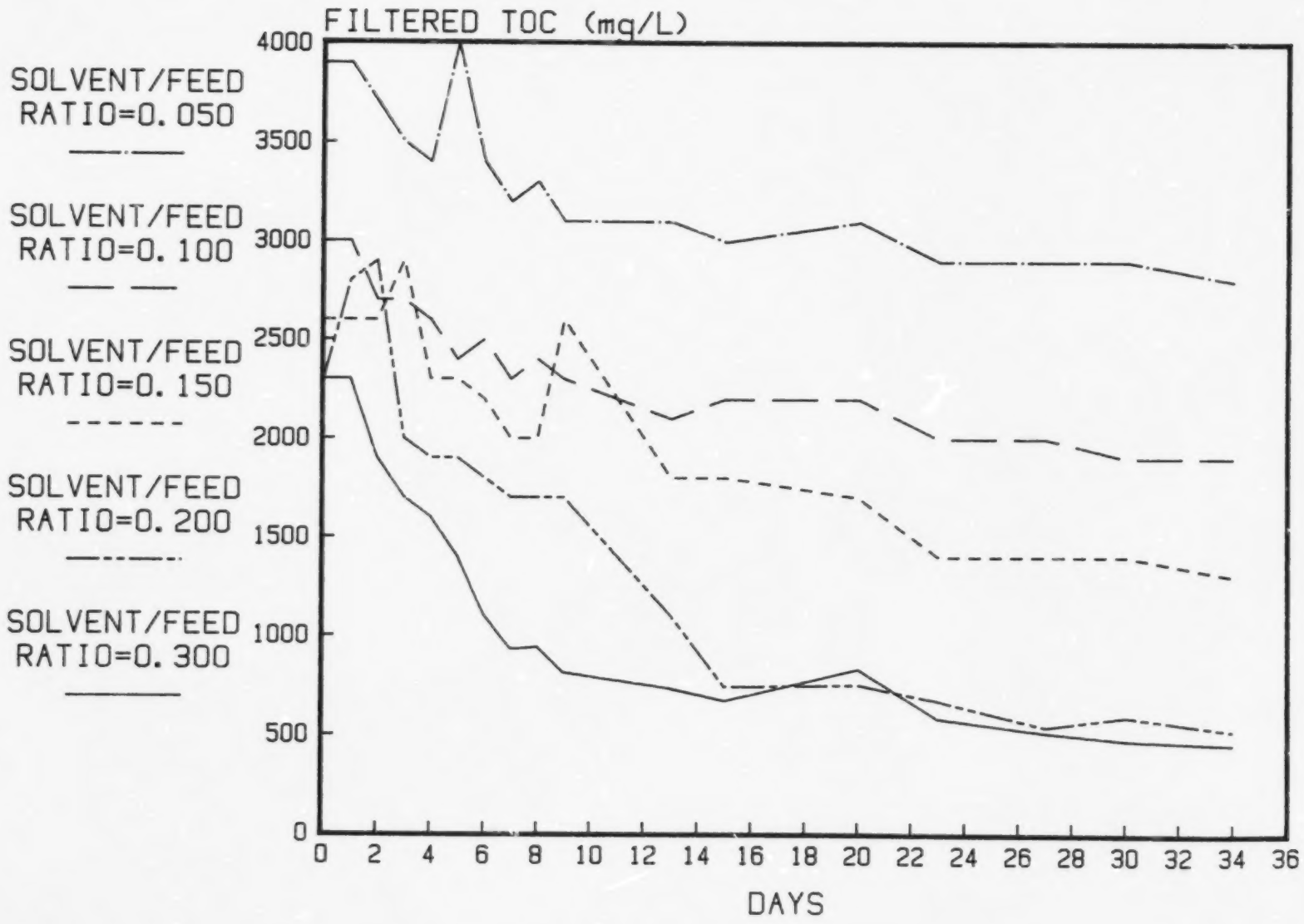
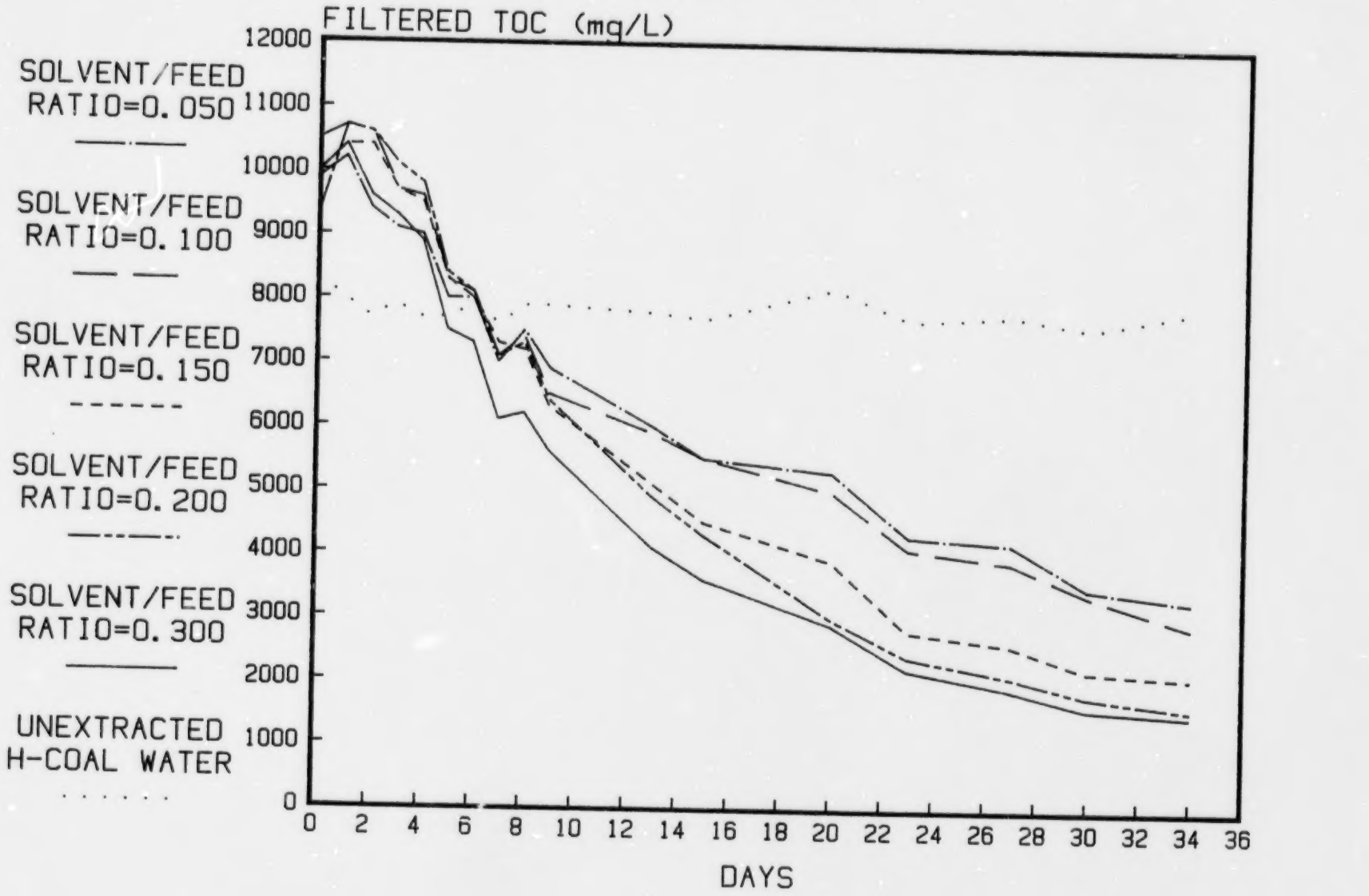


FIGURE 6-8

SHAKE FLASK BIODEGRADATION OF MIBK-EXTRACTED STRIPPED H-COAL SOUR WATER - PHASE I



solubility in each flask, ranging from 5,000 to 6,500 mg/L. This resulted in the uniformly high initial TOC levels in the shake flasks independent of the MIBK solvent-to-feed ratio used in the wastewater extraction. The decline in TOC levels shown in Figure 6-8 were very likely due to volatilization of MIBK since the biomass was completely inactive at the end of the biodegradation period.

The 2-octanone extracted wastewaters contained much lower levels of residual solvent as determined by GC analysis. Residual 2-octanone ranged from 100 - 200 mg/L. There was no information in the literature on the toxicity of either MIBK or 2-octanone on aerobic biological organisms. It appears, however, that the residual 2-octanone had little or no-toxic effect in the shake flask systems.

The refractory TOC levels in both of the biodegradable 2-octanone extracted wastewaters was approximately 550 mg/L. The observed reduced colour intensity in the biodegradable systems at the conclusion of the Phase I investigation, relative to those systems which were inhibited, indicated that some colour compounds were degraded as well as adsorbed on the sludge.

6.3.3. Batch Solvent Extraction and Biotreatability - Phase II

In Phase II of the preliminary treatability study, 10 batch solvent extractions were carried out on the ammonia-stripped H-Coal sour water.

Before introduction of the extracted aqueous phase into the shake flask biological treatment systems, the samples were heat treated and air stripped to remove residual solvent to less than 50 mg/L as determined by GC analysis. An organic loading of 0.2 g TOC/g MLSS was subsequently established in each shake flask experiment by mixing appropriate volumes of

heat treated and extracted wastewater and sludge. The solvent-to-feed ratio and strength of the extracted wastewaters in each biodegradation experiment is given in Table 6-7, Section 6.2.2.

Biodegradability was observed by the amount of TOC removal over a 14-day period. The biological solids used were those from the biodegradable 2-octanone-extracted wastewater systems of the Phase I work. The biological systems were, therefore, acclimated to degradable organics in the H-Coal sour water.

The biodegradation curves for the MIBK and 2-octanone-extracted wastewaters in Phase II of the study are shown in Figures 6-9 and 6-10, respectively. From these curves, it appears that a minimum solvent-to-feed ratio between 0.05 and 0.100 is required for both solvents to render the ammonia-stripped H-Coal sour water biodegradable for an initial organic loading of 0.2 gTOC/gMLSS in the batch systems. In addition, a refractory TOC level of approximately 750 mg/L was measured in each of the biodegradable wastewaters.

Each of the biodegradable systems required 7 days to exhaust the non-refractory fraction. This was also the case for the MIBK extracted system at 0.100 solvent-to-feed ratio where a significant residual solvent level was initially present due to a procedural error. Thus, residual MIBK solvent at approximately 600 mg/L (estimated) in the aqueous phase did not appear to inhibit the overall biological degradation rate of non-refractory organics in the extracted H-Coal waste.

At the conclusion of the shake flask experiments, "effluent" samples were taken for total and individual phenols analysis. Total phenols were analyzed by the 4AAP method. The

FIGURE 6-9 SHAKE FLASK BIODEGRADATION OF MIBK-EXTRACTED H-COAL STRIPPED SOUR WATER - PHASE II

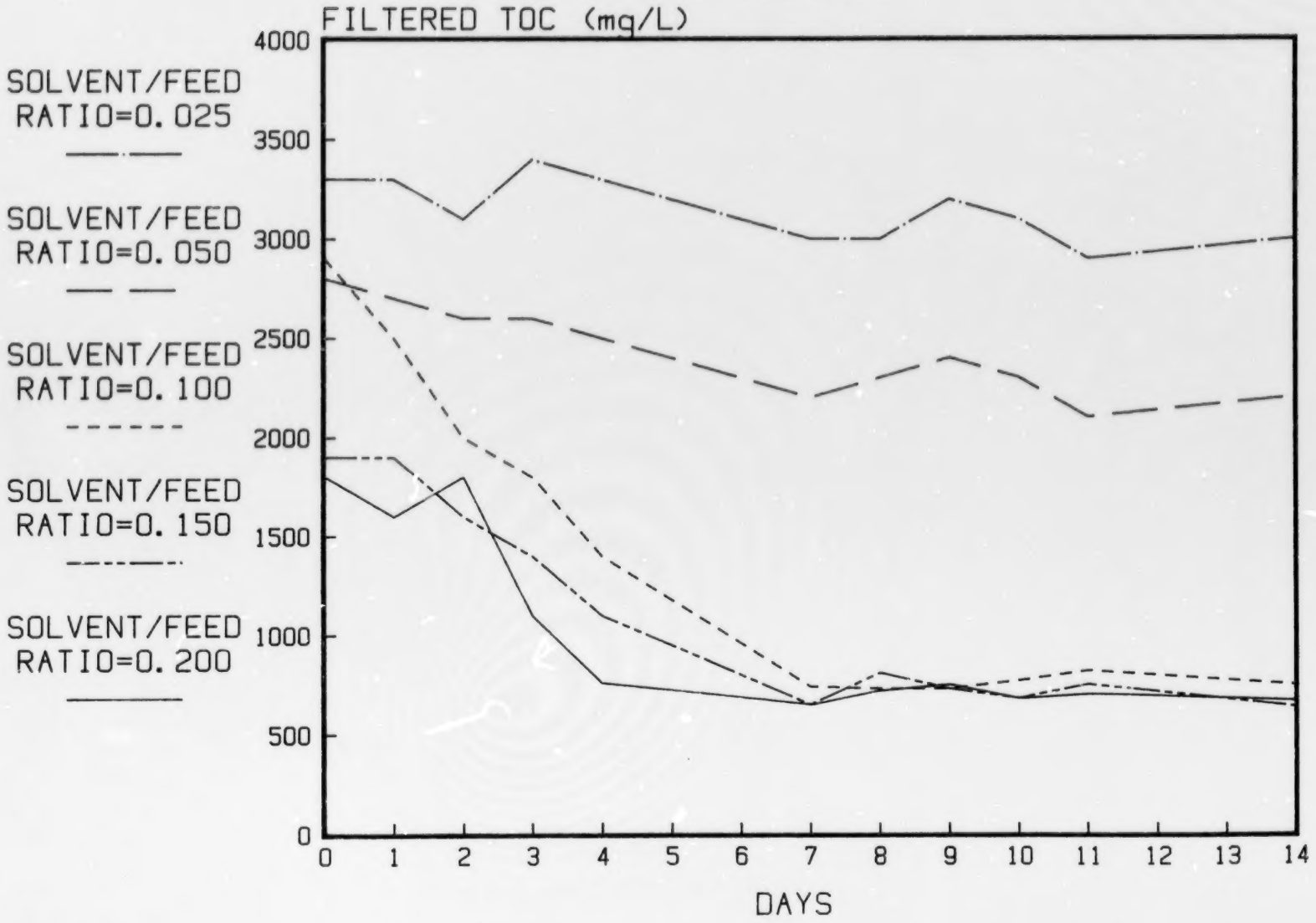


FIGURE 6-10 SHAKE FLASK BIODEGRADATION OF 2-OCTANONE-EXTRACTED H-COAL STRIPPED SOUR WATER - PHASE II

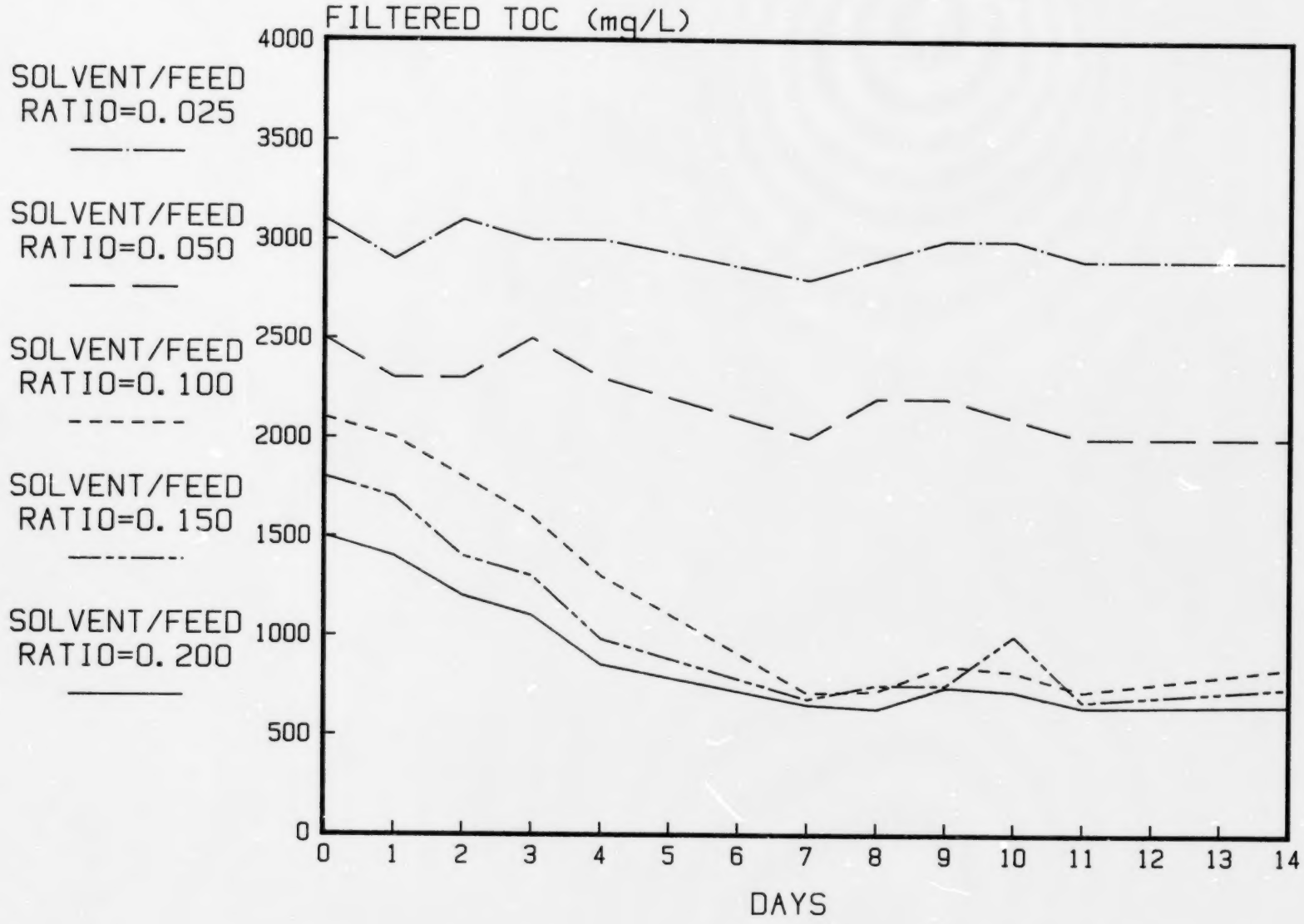


TABLE 6-10 TOTAL AND INDIVIDUAL PHENOLIC COMPOUNDS REMAINING IN STRIPPED H-COAL SOUR WATER FOLLOWING BATCH SOLVENT EXTRACTION AND SHAKE FLASH BIODEGRADATION.

Solvent	Solvent-to-feed Ratio	Total Phenols (4AAP Method)	Phenol (HPLC)	M-Cresol (HPLC)	O-Cresol (HPLC)	o,m,p-Cresol (HPLC)	Sum of Phenol & Cresols (HPLC)
None	0	5380	2215	775	430		3420
2-octanone	0.025	1840	1560	290	150		2000
"	0.05	939	785	70	75		930
"	0.10	2.4	1.6			0.7	2.3
"	0.15	2.6	1.0			0.5	1.5
"	0.20	2.8	1.3	0.7	0.5		2.5
MlBK	0.025	1970	1640	350	230		2220
"	0.05	1224	1020	90	120		1230
"	0.10	2.2	0.9	0.6	0.2		1.7
"	0.15	2.1	0.5	0.3	0.1		0.9
"	0.20	2.5	0.9	0.6	0.2		1.7

HPLC analysis for individual phenolic compounds was made on the distilled fraction generated by the 4AAP analysis. The results are tabulated in Table 6-10.

The data in Table 6-10 indicate that the majority of total phenols in the "effluent" are pure phenol and cresols. At solvent-to-feed ratios greater than 0.10 for both MIBK and 2-octanone, the total phenols, pure phenol, and O, M & P-cresols are degraded to low levels. The maximum initial levels of these compounds observed to biodegrade were 1,760, 1,200, and 200 mg/L respectively.

Colour removal was qualitatively comparable to that observed in the Phase I evaluation. Thus, while some minor amount of degradation occurred, it appears that colour compounds and suspended material accounts for a significant proportion of the biorefractory organic material in the extracted wastewaters. As noted previously, the biorefractory material may largely consist of polymerized polyhydric phenols, such as resorcinol, which has appeared in an analysis of ammonia-stripped H-Coal combined sour water given in Table 4-41, Section 4.3.3.

6.3.4. Summary

The screening investigation of minimum solvent extraction pretreatment coupled with bio-oxidation treatment of H-Coal process wastewater has indicated that such an approach may be a feasible means of reducing the cost of extraction and handling of by-product phenols in coal conversion plants while maintaining adequate control of aqueous organic contaminants. The optimum solvent evaluated in this work was 2-octanone, due primarily to its low solubility in the aqueous phase compared to MIBK. The nature of the biorefractory material was not elucidated in this work. The characteristics of this fraction could have a significant

effect on tertiary pollution control requirements and process options, especially where an effluent suitable for reuse is desired. The effect of minimum extraction on nitrification was not evaluated. In particular, the suitability of the extracted waste as a carbon source for a denitrification reactor coupled to a nitrification reactor has not been explored. Due to the high ammonia levels in coal conversion wastes, biological nitrification /denitrification following minimum solvent extraction pretreatment may provide a relatively low cost approach to combined organic contaminant and ammonia removal.

7. CONCLUSIONS AND RECOMMENDATIONS

The primary objective of this investigation was to identify environmental impact in terms of gaseous, aqueous and solid waste discharges from direct and indirect coal liquefaction technologies being considered for commercial application in Canada by the end of the decade. The investigation also included a review of relevant wastewater pollution control processes and a lab-scale screening evaluation of minimum solvent extract pretreatment and biodegradability of H-Coal process wastewater. From this work, a number of conclusions and recommendations can be made:

7.1. Conclusions

1. From an extensive review of the literature, identification has been made of significant or potentially significant air, water, and solid wastestreams emanating from conceptual commercial-scale coal conversion plants incorporating the selected processes (see Section 4 for detailed listing). Due to impact of feed coal composition on environmental parameters, the available data on the characteristics of these wastestreams are useful only as an approximation of such wastes which would be generated from conversion of Canadian coals. For some wastes, such as spent catalysts or wastewater treatment sludges, little or no information is available in the literature.

2. Given that North American commercial-scale coal conversion facilities are only now coming on-stream, available design and operating data concerning process wastewater treatment options is limited almost exclusively to bench-scale evaluations conducted under ideal conditions. Work to date has focused primarily on process wastewater chemistry and means of reducing combined inhibitory or toxic effects of organic and inorganic contaminants on biological systems.

3. Total process water reuse is currently being practised at the SASOL II facility in South Africa. Their experience suggests that reclamation of high-strength process wastewaters will be extremely difficult and costly, especially in areas of net positive precipitation. Reuse schemes involving cooling towers as the ultimate treatment stage have been proposed for North American plants, although the feasibility has not yet been demonstrated.

4. The screening evaluation of minimum solvent extraction pretreatment followed by bio-oxidation of ammonia-stripped H-Coal process sour water has shown that:

   i) MIBK and 2-octanone solvents, contacted at solvent-to-feed ratios between 0.05 and 0.10, render the wastewater biodegradable. The two solvents exhibited very similar extraction efficiency for total phenols, pure phenol and cresols. 2-octanone is the preferred solvent due to its low solubility in the wastewater such that residual solvent stripping from the extracted waste is not required before bio-oxidation treatment.

   ii) determination of individual polyhydric phenols by HPLC technique was not feasible. It appears that these compounds undergo polymerization in the raw waste and form colloidal suspensions during acid preservation of samples for analysis. The consistent biorefractory TOC level of 750 mg/L in all biodegradable systems appears to consist in large part of colour compounds and suspended material, likely originating from phenolic species in the waste.

   iii) this approach to bulk organic and trace contaminant removal may be a feasible means of reducing the cost of

treatment by drastically reducing solvent use and by-product phenols handling requirements.

7.2. Recommendations

1. Future testing of Canadian coals in process development or pilot coal conversion processes should include, where possible, rigorous sampling and characterization of obtainable air, water and solid wastes and by-product streams. Given adequate waste volumes, pollutant control screening studies should be conducted during this stage of a commercial project to generate environmental data from which information gaps can be identified and input can be made at the earliest stage to conceptual plant designs.

2. Water requirements and the extent of water reuse in a coal conversion facility will have a large impact on plant economics and environmental impact. Fresh water availability and local, provincial and federal discharge guidelines, including thermal pollution criteria, are primary factors influencing the need for water reuse in a commercial plant. An investigation of the current technology, costs, and impact on coal conversion and downstream process design of water reuse options for specific Canadian proposed commercial plants is strongly recommended in order to assist and accelerate development of environmental guidelines for near-term plants.

3. Alternate process wastewater pretreatment methods such as wet air oxidation or anaerobic filters, where destruction of bulk organic and toxic chemical load may yield net positive energy, should be evaluated to reduce or replace solvent extraction pretreatment and the corresponding reduction in by-product phenol production. Aerobic treatment of effluents from pretreatment processes should involve nitrification/denitrification removal of non-strippable ammonia

along with destruction of residual organic compounds. The high-rate biological fluidized-bed process should be evaluated for this purpose in addition to the activated sludge/activated carbon process.

4. It is recommended that an investigation be conducted to verify or develop analytical methods to determine polymerizable organics species and organo-metallic compounds potentially present in raw and treated coal conversion wastewaters respectively.

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APPENDIX A

TABLE A-1 COAL GASIFICATION PROCESSES

A. 1st Generation Commercial Processes

(i) Fixed-Bed Gasifiers:

Wilputte[a]

Woodall-Duckham Two-Stage[a]

Wellman-Galusha[a]

Wellman Incandescent/Black, Sivals & Byson (BS & B)[a]

Riley Morgan Producer[a,b]

Lurgi Dry-Ash[a,b]

Lurgy MKIV Dry-Ash[b]

(ii) Entrained-Flow Gasifiers:

GKT (Koppers-Trotzek)[b]

Foster-Wheeler Stoic[a]

(iii) Fluidized-Bed Gasifiers:

Winkler[a]

High Temperature Winkler[b]

B. 2nd Generation Processes

(i) Fixed-Bed Gasifiers:

British Gas Corp. BGC /Lurgi (Slagging Lurgi)[b]

High Pressure Lurgi[b]

(ii) Entrained-Flow Gasifiers:

Texaco Gasification[b]

Ruhrgas/Ruhrchemie Texaco[b]

KBW (Koppers/Babcock & Wilcox)[b]

ATM Entrained Bed[a]

Shell/Koppers[b]

Kilngas (Allis-Chalmers)[a]

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a = air-blown, nitrogen in product gas

b = oxygen-blown

TABLE A-1 (continued)

(iii) Fluidized-Bed Gasifiers:

Westinghouse Agglomerating PFB[a]

Institute of Gas Technology (IGT)
U-Gas Agglomerating FB[a]

IGT HYGAS[b]

COED-COGAS (FMC)

(iv) Molten-Bath Gasifiers:

Saarberg/Otto[b]

Sumitomo Molten-Iron Gasifier[b]

(v) Unclassified Gasifiers:

VEW Process (German)

Bergbau-Forschung Nuclear-Aided
Hydrogasification

C. 3rd Generation Processes

(i) Fixed Bed Gasifiers:

Westfield Composite Gasifier[b] (BGC)

KGN Process (German)[a]

(ii) Entrained-Flow Gasifiers:

Bi-Gas[b] (Bituminous Coal Research (BCR))

IGT Riser Cracking Gasification[a]

(iii) Fluidized-Bed Gasifiers:

Exxon Catalytic Gasification[b]

Tri-Gas (BCR)[b]

CO_2 - Acceptor

IGT Peatgas[b]

(iv) Molten-Bath Gasifiers:

Humbolt-WEDAG (German)[b]

Rockgas Molten - Salt[a,b]

TABLE A-1 (continued)

(v) Unclassified Gasifiers:

Hitachi Gasifier

Stone & Webster Nuclear-Aided

TABLE A-2 COAL LIQUEFACTION PROCESSES

A. 1st Generation Processes:

- Bergius - Pier (I.G. Farben)[a]
- Lurgi Ruhrgas[c]

B. 2nd Generation Processes:

- SRC-1/TSL[b] (Solvent Refined Coal/ Two-Stage Liquefaction)
- H-Coal (Hydrocarbon Research Inc.)[a]
- Modified Bergius/I.G. Farben/ Saarbergwerke[a]
- Modified Bergius/I.G. Farben/ Ruhrkohle[a]
- SRC/Mitsui[b]
- Modified Lurgi Ruhrgas[c]

C. 3rd Generation Processes:

- SRC-II[b]
- Exxon Donor Solvent (EDS)[b]
- Cities Service/Rockwell (CS/R) Flash Hydropyrolysis[c]
- Dow Liquefaction Process[a]
- Supercritical Gas Extraction[b]
- Consol Synthetic Fuels (CSF)[b]
- Gulf Catalytic Coal Liquids (CCL)[a]
- Liquid Solvent Extraction[b] (LSE)
- Coalcon (Union Carbide)[c]
- Genmin/Sentrachem[b] (South Africa)
- Occidental Research Process[c]

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a = Catalytic Direct Hydroliquefaction

b = Non-Catalytic Direct Hydroliquefaction

c = Pyrolysis (Liquid and Char Products)

TABLE A-3

COAL GASIFICATION PROJECTS WORLDWIDE: OPERATIONAL OR UNDER CONSTRUCTION

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
WELLMAN-GALUSHA (McDowell-Wellman Eng.)	Hazelton Brick Gasification Hazelton, Pennsylvannia	Hazelton Brick Co.	Operational 1940. Four 20T/D units on anthracite. Presently on standby until natural gas price increases.	See Glen Gery Project below
WILPUTTE (Wilputte Corp.)	Holston Producer Gas Plant Kingsport, Tennessee	Holston Defence Corp. (div. of Eastman Kodak)	Operational 1942. Twelve 24T/D units on low-S bituminous. Presently run 2 units and rotate duty.	N/A
WELLMAN-GALUSHA	Glen Gery York Operations York, Pennsylvania. Also operations at: New Oxford, Pennsylvania Shoemakersville, Penn.	Glen Gery Corp. Acurex-Aerotherm Corp. U.S. DOE " " " " " "	Operational 1953. Eight 20T/D units. 1977 added new 24 T/D unit on anthracite (0.7%S) Eight 20T/D units on anthracite. One unit on anthracite.	No tar formation with anthracite. Very high quench water recycle, blowdown to municipal sewer. Ash sold as landfill. Dust, air pollution low, use brick kilns as after-burners.
WELLMAN- GALUSHA	National Lime & Stone Project. Carey, Ohio.	National Lime & Stone Co.	Operational 1955. One 24T/D unit on low-S bituminous. Presently on standby until natural gas price increases.	All waste streams incinerated. Ash non-leachable, buried. Air meets EPA permit.
WELLMAN-GALUSHA	Ohio Coke Project Ashtabula, Ohio	Olin Chemical Corp.	Operational 1963. Petroleum coke feed to one 5' dia. unit. Produces CO for phosgene production.	Quench water: solids removal by emulsification - settling, to municipal sewer. Ash for landfill. Product gas scrubbed, through carbon bed and MEA extraction purification.
WELLMAN-GALUSHA	Pennsylvania Coke Project	Gulf & Western Co (of New Jersey Zinc)	Operational 1963. Foundry coke feed to one 6.5' dia. unit. Produces CO for chemicals.	Almost identical to Ohio Coke project.
LURGI DRY-ASH (Lurgi Kohle und Mineralöl-technik GmbH)	Kosovo Kombinant Plant Pristina, Yugoslavia	N/A	Operational mid 60's. Six 420T/D units on lignite.	Radian Corp. 1979 performed monitoring program for atmospheric Commission from plant, several chemical plants and coal-fired power station in nearby region. Nitrogen, sulphur, phenolic and other organic emissions and tar and oil aersols identified. Note: data for old plant using old Lurgi technology. Phenolsovan unit and ammonia stripping by-product recovery.
WINKLER (Davy Powergas GmbH)	Gorzade, Yugoslavia Kutahya, Turkey Madras, India	N/A N/A N/A	Prior to 1976, 36 gasifiers at 16 locations worldwide. Presently 6 gasifiers operating (total) at 3 locations shown to produce synthesis gas for ammonia.	N/A

TABLE A-3 (Continued)

PROCESS SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
BGC/LURGI (Lurgi Kohle und Mineralöl-technik GmbH)	Westfield Gasification Testing Program, Westfield, Scotland.	British Gas Corp. Conoco, Transco, EPRI, Panhandle Pipeline, Texas. Eastern, National Gas Pipeline.	Program initiated 1965 with 5 gasifiers. Program ended 1980 after development of BGC/Lurgi slagging gasifier to 100T/D pilot scale. New program underway for development of BGC composite gasifier at 150 T/D scale.	N/A
HYGAS (Institute of Gas Technology)	Hygas Pilot Plant Chicago, Illinois.	Institute of Gas Technology American Gas Association	75 T/D pilot unit operational 1973 on Illinois no. 6 and Missouri no. 10 coal. Project completed 1981.	Extensive environmental information available in literature.
TEXACO GASIFICATION (Texaco Development Corp.)	Montebello, California Morgantown, West Virginia	Texaco Development Corp. Texaco Development Corp.	Two 15-20T/D pilot units initially operational 1948 for oil partial oxidation. Many coals, chars, and solid residues tested since mid 70's. Used for synthesis gas and hydrogen production. 100 T/D pilot unit	Wastewater data published in literature. Water contains mainly carboxylic acids, ammonia and sulphur compounds. Usual gas clean-up wastes. Slagged ash innocuous, non-leachable. D'Appolonia designing and siting 400 acre waste disposal facility.
WESTINGHOUSE AGGLOMERATING PFB (Westinghouse Electric Corp.)	Waltz Mill, Pennsylvania	Westinghouse Electric Corp. U.S. DOE	15 T/D PDU operational 1975. scale-up unit 200 T/D operational early 1982.	SO_2 absorption in bed. Ash studied for concrete additive.
RILEY MORGAN GAS PRODUCER (Riley Stoker Corp.)	Worcester, Massachusetts	Riley Stoker Corp.	Operational 1975. Full-scale 150T/D unit on many U.S. coals	N/A
BI-GAS (Stearns - Roger Inc.)	Homer City, Pennsylvania	Bituminous Coal Research American Gas Association Phillips Petroleum Co.	120 T/D pilot unit operational 1976. Attached fluidized-bed methanation PDU operational 1982. Montana lignite and various bituminous and sub-bit. coals.	N/A
WELLMAN-GALUSHA	Binghampton Brick Project Binghampton, New York	Binghampton Brick Co. U.S. DOE	Operational 1978. Two 24 T/D units on anthracite. Presently on standby until natural gas price increases.	See Glen Gery Project above.
WELLMAN-GALUSHA	Fort Snelling Demonstration Project St. Paul, Minnesota	Bureau of Mines U.S. DOE	Operational 1978, 1979. One 24 T/D unit to fire kiln.	N/A
HIGH TEMPERATURE WINKLER (RHEINBRAUN) (Davy Powergas GmbH)	Rheinbraun Cologne Gasification Project Frechen (Cologne), W. Germany	Rheinische Braunkohlenwerke AG	25 T/D pilot unit operational 1978.	EPRI has evaluated conceptual plant on lignite with waste treatment included. (EPRI-AP-1592)

TABLE A-3 (Continued)

PROCESS SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
SHELL/KOPPERS (Krupp-Koppers GmbH)	Shell Hamburg Gasification Project Hamburg, W. Germany.	Shell International Deutsche Shell AG Krupp-Koppers GmbH	140 T/D pilot unit operational 1978 on coal dust. Synthesis gas producer.	N/A
RUHRKOHLE/RUHRCHEMIE/TEXACO (Texaco Development Corp.)	Texaco Oberhausen-Holten Project Oberhausen-Holten, West Germany.	Ruhrkohle AG Ruhrchemie AG	140 T/D demonstration scale unit Operational January 1978.	Wastewater less concentrated in carboxylic acids due to quench at lower temperature. No other organics of any significance. Slagged ash non-leachable. Usual gas purification wastes, sulphur related mainly H_2S, COS.
ATM ENTRAINED-BED (Combustion Engineering)	Two-stage Entrained Gasification Program Windsor, Connecticut	Combustion Engineering Gulf States Utilities U.S. DOE	120 T/D pilot unit operational June 1978. Many coals tested. Program complete 1982. Plans for 150 MW generation project by end of 1982 on hold. Proposed site is Lake Charles, Louisiana.	N/A
FOSTER-WHEELER STOIC (Foster-Wheeler Corp.)	University of Minnesota Project Duluth, Minnesota	University of Minnesota U.S. DOE	Operational October 1978. 72 T/D unit on sub-anthracite, bituminous and sub-bit. coals to produce 180 BTU gas and no. 6 fuel oil.	Oak Ridge National Lab. performed environmental monitoring program through construction and two years on-line. Evaluated with Wellman-Galusha for general environmental impact. (ORNL/TM-7361)
LURGI DRY-ASH	Lünen, W. Germany	Steinkohlen Electrizitat AG (STEAG)	Operational 1979. Supplies low-BTU gas to 170 MW power generating system.	N/A
SAARBERG/OTTO (Dr. C. Otto & Co.)	Saarberg Furstenhausen Project Furstenhausen/Saar, W. Germany	Saarbergwerke AG Dr. C. Otto & Co	250 T/D pilot unit operational 1979. 264 T/D and 1000 T/D units for power generation scheduled operational 1985.	N/A
HIGH PRESSURE LURGI (Lurgi Kohle und Mineralöltechnik GmbH)	Ruhrgas Dorsten Project Dorsten, W. Germany	Ruhrgas AG Ruhrkohle AG STEAG Lurgi Kohle und Mineralöltechnik GmbH	240 T/D pilot unit operational September 1979.	N/A
WELLMAN-INCANDESCENT/BS&B (Black, Sivalls & Byson Inc.)	Caterpillar Tractor Project York, Pennsylvania	Caterpillar Inc. U.S. DOE	Operational late 1979. One 130 T/D unit on bituminous coal. Plan additional units at other plants if successful.	All phenol-containing streams incinerated. Others sent to municipal sewer. Ash sold as land fill.
WELLMAN-GALUSHA	Can-Do Gasification Project Hazelton, Pennsylvania.	Can-Do Inc. U.S. DOE	Operational 1980. Two 24 T/D units on anthracite.	See Glen Gery Project above.

TABLE A-3 (Continued)

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
TEXACO GASIFICATION	TVA Ammonia From Coal Project Muscle Shoals, Alabama	Tennessee Valley Authority Texaco Development Corp.	Initially operational 1980. Several long shut-downs due primarily to slag discharge problems. Re-start after design changes scheduled February 1982. 135 T/D unit on Illinois no. 6 bituminous coal to synthesis gas.	Brown & Root Inc. published conceptual design of waste treatment plant. Selexol acid gas treatment, Holmes-Stretford sulphur recovery. Slagged ash landfill quality.
TEXACO GASIFICATION/ Westinghouse Gas Turbine	Dow Gasification Project Plaquemine, Louisiana.	Dow Chemical Company	Operational January 1981 on Illinois no. 6 coal to produce 15 MW electric power. Presently looking at 1000-2000 T/D Texaco unit on lignite for 100 MW power. Dow claims to be attempting to convert 75% of internal energy needs to syngas-based by 1995.	High efficientcy gas clean-up required. Details unavailable. See above for wastewater data.
WELLMAN-GALUSHA	Howmet Aluminum Project Lancaster, Pennsylvania	Howmet Aluminum Company U.S. DOE	Operational 1981. One 24 T/D unit on anthracite.	See Glen Gery Project above.
WELLMAN-GALUSHA	Pike County Project Pikeville, Kentucky.	Appalachian Regional Commission. Kentucky DOE U.S. DOE	Operational late 1981. Two 36 T/D units on low-S bituminous coal. Gas used for district heating.	Filed "Statement of Negative Environmental Impact".
KILNGAS PROCESS (Allis-Chalmers Inc.)	KilnGas Demonstration Project Wood River Station, East Alton, Illinois.	Large consortium of 17 utilities headed by Allis-Chalmers and the State of Illinois.	Under construction. Presently ahead of schedule for early 1983 start-up. 820 T/D high-S bituminous for 50 MW electric power. 60 T/D pilot unit operated since 1971 at Oak Creek, Wisconsin.	Construction permit issued by State of Illinois Environmental Protection Agency.
LURGI MKIV DRY-ASH & METHANATION (Lurgi Kohle und Mineralöltechnik GmbH)	Great Plains Gasification Project. Beulah, North Dakota.	ANR Coal Gasification Co. (32.5%) Tenneco SNG (30%) Transco Coal Gas Co.(22.5%) PGC Coal Gasification Co. (15%)	Construction began October 1981 for 1984 start-up. 7000 T/D N. Dakota lignite to SNG in Phase I, double capacity in Phase II.	Environmental Impact Statement (EIS) issued. Phosam-W ammonia recovery recently selected. 125,000 T covered coal storage barn. Coal fines sold to power plants.
TEXACO GASIFICATION/ GE Gas Turbine	Coolwater Gasification Project Daggett, California.	Southern California Edison Company. Electric Power Research Institute (EPRI). Texaco Development Corp. Bechtel Power Corp. General Electric Co. U.S. DOE	Construction begin 1982. Final detailed engineering 60% complete. Among finalists for SFC funding assistance although said to have sufficient private funds. 1000 T/D to fire existing 65MW and eventual 100 MW combined-cycle power systems.	Construction permit approved by State of California. Conceptual design with environmental processes published (EPRI AF-880).
BERGBAU-FORSCHUNG NUCLEAR-AIDED (Bergbau-Forschung GmbH)	Wesseling Nuclear Gasification Project. Wesseling, W. Germany	Bergbau-Forschung GmbH Braunkohlewerke AG	Under construction for late 1982 completion. 150 T/D demonstration unit. Hydrogen supplied by adjacent Winkler pilot unit. Waste nuclear heat transferred by hot helium gas.	N/A

TABLE A-3 (Continued)

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
SUMITOMO PROCESS (Sumitomo Metal Industries Ltd.)	Kashima, Japan.	Sumitomo Metal Industries	60 T/D pilot unit recently constructed. Claim 98% gasification of feed in molten-slag bath. 1500 T/D commercial-scale unit to be constructed by 1985. Sumitomo also has liquefaction process at 1 T/D PDU scale in operation for several months.	N/A
HITACHI PROCESS (Hitachi Limited)	2000 Sunshine Project Fukushima (Iwaki City) Japan.	Japan Electric Development Co.	Pilot unit under construction. Process leaves 26 to 30% coal as unconverted char.	N/A
VEW PROCESS (Vereinigte Elektrizitats-werke AG)	Dortmund, W. Germany	Vereinigte Elektrizitats-werke AG Westfalen AG	24 T/D pilot unit operational 1979, to produce electric power. Plans for 360 T/D demonstration unit operational 1982 at Werne and 5000 T/D commercial plant operational 1985.	N/A

TABLE A-4

COAL GASIFICATION PROJECTS WORLDWIDE: PROJECTS EXPECTED ONSTREAM BY 1990

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
SHELL/KOPPERS (Krupp-Koppers GmbH)	Shell Netherlands Project Moerdijk, The Netherlands	Shell International Petroleum Maatschappij BV Krupp-Koppers GmbH	Scheduled to begin construction late 1981. 1000 ton/d to syngas for combined-cycle power-generation.	N/A
WESTINGHOUSE AGGLOMERATING PFB (Westinghouse Electric Corp.)	Southern Italy	Fiat TTC Ansaldo Westinghouse Electric Corp.	Agreement signed Sept. 1981 to construct demonstration 140 MW combined-cycle power-generation plant. Onstream 1986.	N/A
GKT (KOPPERS-TOTZEK) (Gesellschaft für Kohle-Technologie, U.S.)	Libiaz Coal Gasification Project Libiaz, Poland	Kopex	Construction to begin mid-1982. Silesian bituminous coal to 950 million m^3/yr. SNG for industrial and municipal heating fuel	Rawgas desulphurized in Rectisol, sulphur recovered from Claus unit. IFP (catalytic) final gas purification. Krupp-Katox plant for treatment of liquid wastes (bio-oxidation).
LURGI MKIV DRY-ASH (Lurgi Kohle und Mineralöltechnik GmbH).	Le Havre, France	Gaz de France	Construction to begin mid-1982. 1000 ton/d imported coal to SNG	N/A
GKT (KOPPERS-TOTZEK)	Rio Grande do Sul Project Sao Jeronimo, Brazil	Riograndense Nitrogen Fertilizer Co. Petro Brasiliero SA	Detailed engineering begun for phase 1, onstream 1984 2400 ton/d coal to synthesis gas for 600 ton/d ammonia production. Additional town gas production in phase 2.	N/A
U-GAS AGGLOMERATING FB (IGT/Foster-Wheeler Corp.)	MLGWD Industrial Fuel Gas Project Presidents Island (Memphis), Tennessee	Memphis Light, Gas & Water Division (City of Memphis), Foster-Wheeler Corp. U.S. DOE	Detailed engineering complete 1984. 3155 ton/d Kentucky No. 9 high - S coal to fuel gas for industrial complex. U-Gas technology presently being considered by Gaz de France and VEG Gassinstituut (The Netherlands)	Final EIS for project issued May 1981 (DOE/EIS-0071)
LURGI MKIV DRY-ASH and TEXACO GASIFICATION	WyCoal Project Douglas (Converse Co.), Wyoming	WyCoal Gas Inc. Ruhrgas Carbon Conversion Inc.	Waiting SFC price and loan guarantees. $40 million invested in project since 1971. 16,000 ton/d sub-bituminous coal to high-BTU SNG. Construction could begin late 1982. Texaco gasifier to process coal fines and Lurgi ash residue.	$31.1 million spent on environmental, engineering, socio-economic study plus land acquisition. Environment document released 1974 by SERNCO Contractors.

TABLE A-4 (Continued)

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
WESTINGHOUSE AGGLOMERATING PFB/Westinghouse W-501D Combustion Turbine	Roy S. Nelson Power Station Lake Charles, Louisiana	Westinghouse Electric Corp. Gulf States Utilities Co. Dravo Engineers and Constructors, Stone & Webster Engineering Corp., Arthur Anderson & Co., U.S. DOE.	Major DOE grant Oct. 1981 for study of 100 MW power generation and export steam production from two gasifier modules.	Energy Impact Associates to perform environmental studies. Gasifier produces virtually no tars or oils, low water requirement, ash residue suitable for landfill or concrete filler.
TEXACO GASIFICATION	San Ardo Cogeneration Project	Pacific Gas & Electric Co. Texaco Development Co. U.S. DOE	Feasibility and conceptual design complete mid-1982. 17,000 ton/d coal for combined-cycle power generation and export steam to industrial complex.	Similar to Coolwater project. See EPRI AF-880 report.
LURGI DRY-ASH	Transco Gasification Project Calvert, Texas	Transco Energy Corp. U.S. DOE	Feasibility study extended for mid-1982 completion. 16,500 ton/d Texas lignite to low-BTU gas, ammonia, sulphur.	N/A
LURGI MKIV DRY-ASH	Tenneco Gasification Project Wilbaux & Glendive, Montana	Tenneco Coal Gasification Co. U.S. DOE	$20 million of $40 million required funds awarded by U.S. DOE. Engineering underway.	Ecology & Environment Inc. (Buffalo, N.Y.) awarded $1.7 million for environmental study.
LURGI MKIV DRY-ASH	Crow Gasification Project Crow Indian Reservation, Billings, Montana	Crow Tribe (Washington, D.C.) U.S. DOE Utah Resources International Pacific Gas & Electric Co.	Engineering underway by Fluor Corp. 12,000 ton/d coal to high-BTU gas and by-products.	Council on Energy Resource Tribes has prepared detailed environmental document.
LURGI MKIV DRY-ASH	Peking, China	China National Technology Import Lurgi Kohle und Mineralöl-Technik GmbH.	Engineering near completion. Synthesis gas production for 1000 ton/d ammonia and 300 ton/d methanol.	N/A
LURGI MKIV DRY-ASH	Burnham Project Four Corners (San Juan Co.), New Mexico	El Paso Natural Gas Co. Ruhrgas AG Pacific Gas & Electric Co.	Negotiations for 15,000 acre-feet/yr. water from Navajo Reservoir and SFC loan-guarantees holding up final engineering work. 7600 ton/d coal to high-BTU gas and methanol	Final EIS released May 1977. Zero-discharge water concept.
LURGI MKIV DRY-ASH	Lake De Smet Project Buffalo, Wyoming	Transwestern Coal Gasification Co. Texaco Corp. Texas Eastern Corp.	Privately funded feasibility study underway early 1981. 38,000 ton/d lignite to SNG. May decide to add methanol and Mobil MTG gasoline synthesis.	Texaco to supply water resources and develop, operate coal mine.

TABLE A-4 (Continued)

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
LURGI MKIV DRY-ASH	Garfield Co., Utah	Utah Resources International	Feasibility study underway. 17,000 ton/d to SNG.	Preliminary EIS for thermal generating station being revised for gasification plant
BGC/LURGI (Lurgi Kohle and Mineralöl-technik GmbH)	Noble County Demonstration Project. Noble Co., Ohio	Conoco Coal Development Co. Gulf Oil Corp. Sun Oil Corp. Tenneco Transco EPRI Texas Eastern Co. Natural Gas Pipeline Co. Panhandle Co.	Conceptual design complete and engineering begun. 1200 ton/d bituminous coal to SNG, ammonia and chemical feedstocks. Further gov't funding required for construction phase.	N/A
WESTINGHOUSE AGGLOMERATING PFB	Lake Charles, Louisiana	Westinghouse Electric Corp. U.S. DOE Gulf States Utilities	Feasibility study for power generation from syngas. 2 gasifiers to fuel 100 MW unit.	Energy Impact Associates to perform environmental study.
WOODALL-DUCKHAM (Le Gaz Integrale)	Seilles, Belgium	Carmeuse SA	Engineering nearing completion. 70 ton/d coal to low BTU-gas.	N/A

TABLE A-5 COAL LIQUEFACTION PROJECTS WORLDWIDE: OPERATIONAL AND UNDER CONSTRUCTION

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
LURGI DRY-ASH/ Synthol & Arge Fischer-Tropsch Synthesis	SASOL I Secunda (Sasolburg), South Africa	South African Coal, Oil & Gas Corp.	Operational 1955 . 14,000 ton/d high-ash low grade coal to gasoline, liquid and gaseous fuels, and chemical feedstocks. Expansion program initiated 1975 to 19,500 ton/d and double gaseous fuel output. Coal fines used for steam generation.	Rawgas clean-up extensive due to subsequent catalytic processes. COS, H_2S, organic sulphides removed by Rectisol process. Phenolsolvan unit for phenol recovery from aqueous waste. Only 10% removal of polyhydric phenols. Aqueous waste to conventional AS biox units after ammonia stripping and phenolsolvan extraction.
SRC-I & SRC II (Solvent Refined Coal) (Gulf Oil Corp.)	Fort Lewis (Tacoma), Washington	Pittsburg & Midway Coal Mining Co. (Gulf) U.S. DOE	Pilot unit operational 1974. 50 ton/d in SRC-1 mode, 35 ton/d in SRT-II mode on various coals. 6000 ton/d SRC-II demonstration project for Morgantown, W. Virginia cancelled due to excessive cost escalations. Pilot program completed 1981.	Extensive environmental studies on all aspects of SRT-I & II operation. Oak Ridge National Lab. and U.S. DOE involved in most of the studies.
SUPERCRITICAL GAS EXTRACTION (National Coal Board)	Stoke Orchard, Cheltenham, England	National Coal Board	5 kg/h bench unit operational 1975. Detailed design and costing complete for 25 ton/d pilot unit located at Point of Ayr Colliery, North Wales.	Sour water stream contains ammonia, phenolics and absorbed gases. Char gasified for hydrogen make-up.
CS/R FLASH HYDROPYROLYSIS (Cities Services Co.)	Santa Susana, California	Cities Services Co. Rockwell International Corp.	24 ton/d PDU operational 1977. 300 ton/d pilot in design stage at Clairton, Pennsylvania. U.S. Steel Corp. and several other companies will join venture.	Rawgas quench water contains ammonia, absorbed gases and organics. Ammonia and phenol concentration reduction required before biological treatment. Char can be gasified for hydrogen make-up.
MODIFIED BERGIUS/I.G. FARBEN/SAARBERGWERKE (Catalytic Hard Coal Liquefaction) (Saarbergwerke AG)	Volkingen, W. Germany	Saarbergwerke AG Federal Ministry of Technology and Research (BMFT) State Government of Saarland	6 ton/d pilot unit operational 1979 on mainly high-volatile bituminous coal. Detailed engineering underway for 6000 ton/d commercial plant. Construction began mid-1982.	Quenchwater requirement reduced since raw product used to be preheat feed. Solid vacuum bottoms residue gasified in Saarberg/Otto gasifier for hydrogen make-up.

TABLE A-5 (Continued)

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
DOW LIQUEFACTION PROCESS	Midland, Michigan	Dow Chemical Co.	5 kg/hr semi-continuous PDU operational 1979. 5 kg/hr continuous "mini-plant" with complete computer control operational 1981. Engineering conceptual design of 10,000 ton/d plant complete. The negotiation with U.S. DOE for use of H-Coal pilot plant in 1983 for final scale-up work.	Sour quench water contains high levels of ammonia and polar aromatics. Solid vacuum bottom residue gasified for hydrogen make-up.
SRC (SRC-PAMCO) (Catalytic, Inc.)	Wilsonville, Alabama	Southern Company Services Inc. U.S. DOE EPRI	6 ton/d pilot unit operational 1980 to support Newman demonstration plant design. Program completed 1981 after testing of coals and correlation with SRC-I data.	Environmental data correlated with SRC-I data to support EIS for demonstration project.
H-COAL (Hydrocarbon Research Inc.)	Cattletsburg, Kentucky	Ashland Synthetic Fuels Co. U.S. DOE Commonwealth of Kentucky EPRI Standard Oil of Indiana Mobil Oil Corp. Conoco Coal Development Co. Ruhrkohle AG	Operational 1980. 200 ton/d in syncrude mode, 600 ton/d in fuel oil mode. Illinois No. 6 and Kentucky No. 9 coals tested. Run on Wyodak coal to start March 1982. Vacuum resid bottoms gasified in Texaco (Montebello) process for make-up hydrogen.	Quench sour water contains ammonia, absorbed gases (H_2S, COS) and mainly phenolic organics. Ammonia stripped water at approx. 15% strength treated in AS unit. Use adjoining refinery Claus unit for sulphur recovery.
EXXON DONOR SOLVENT (EDS)	Baytown Refinery, Texas	Exxon Corp. U.S. DOE Phillips Petroleum Co. Atlantic Lichfield Co. EPRI Japan Liquefaction Development Co. Ruhrkohle AG	Operational 1980. 200 ton/d pilot unit on Illinois No. 6 up to July 1981. Wyoming sub-bituminous run to be completed by late 1982 followed by Texas lignite.	All waste streams treated at adjoining refinery. Specific data limited.
LURGI RUHRGAS (Flash Pyrolysis) (Lurgi Ruhrgas AG)	Frankfurt, W. Germany	Lurgi Ruhrgas AG	Old LR technology commercialized 1963 at Lukava, Yugoslavia for char production 24 ton/d pilot unit on-stream 1980 focusing on liquid yield and operational improvement plus coal testing.	Ammonia and phenol recovery from sour water required. Product hydroheating creates additional sour water stream.

TABLE A-6 COAL LIQUEFACTION PROJECTS WORLDWIDE: PROJECTS EXPECTED ONSTREAM BY 1990

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
GKT (KOPPERS-TOTZEK)/ ICI METHANOL SYNTHESIS (Gesellschaft für Kohle-Technologie, U.S.)	TVA Murphy Hill Project Murphy Hill, Alabama	North Alabama Coal Gasification Consortium: Santa Fe International Kidder Peabody Co. Air Products & Chemical Co.	Construction was scheduled to begin construction Oct. 1981. Rearrangement in funding due to switch in gasifier technology causing delay. 13,000 ton/d high-S coal to methanol from one process module. Future additional modules will likely use Texaco process.	EIS under revision. GKT process generates comparatively insignificant liquid waste stream. Sulphur compounds only significant problem.
COED-COGAS (FMC Corp.)	Cutler (Perry Co.), Illinois	Illinois Coal Gasification Group. Dravo Corp. U.S. DOE	Plant design underway for 1984 completion. 2,210 ton/d blend of Illinois No. 5 and 6 bituminous to SNG and syncrude. 50 ton/d pilot unit was operated by BCURA Ltd., Leatherhead, Surrey, England.	Environmental Analysis Report being prepared by Gibbs & Hill Inc. DOE preparing draft EIS. Will use Phosam-W ammonia recovery and FMC Dual Alkali desulphurization.
LURGI MKIV DRY-ASH/ KBW/ MOBIL MTG. (KBW-Koppers/Babcock & Wilcox Process)	Hampshire Energy Project Gilette, Wyoming	Hampshire Energy: Kaneb Services Inc. Koppers Co. Northwestern Mutual Life Insurance Co. Metropolitan Life Insurance Co. Sohio	Construction was scheduled to begin mid-1982, onstream 1985. 15,000 ton/d lignite to 19,500 bbl/d gasoline plus chemical feedstocks. Coal fines gasified in KBW process (modified Koppers-Totzek). Project now on hold.	Will employ "extensive water-recycling and energy conservation systems" EIS Filed with Wyoming Industrial Siting Council.
SRC-1/TSL (International Coal Refining Co.)	Solvent Refined Coal Demonstration Project Newman, Kentucky	International Coal Refining Co. (Air Products and Chemicals, Wheelabrator-Frye) Southern Company Services U.S. DOE Alcoa Aluminum Cities Service Co.	Construction was scheduled to begin Oct. 1982, onstream 1986. $135 million congressional funds for final design in 1982. 6,000 ton/d bituminous coal to SRC-I Syncrude. Currently evaluating 2-Stage (ITSL) Process at Wilsonville.	SRC-I Syncrude is highly aromatic and low-S. Final EIS issued July 1981 based on extensive environmental studies at pilot stage. (DOE/EIS-0073).
GKT or TEXACO GASIFICATION/ METHANOL SYNTHESIS	TVA Coal Gasification Project Wakefield, Alabama	Tennessee Valley Authority NASA	Awarded $210 million by U.S. Congress 1981. 10,000 ton/d high-S coal to 96,000 gal/d methanol. Expected onstream 1987. If SFC loan guarantee received will double capacity	N/A
SRC/MITSUI	Mitsui SRC Project Morwell, Victoria, Australia	Mitsui SRC Development Co. (consortium of 4 Japanese and 8 Australian firms)	Construction was scheduled to begin early 1982. 7,000 ton/d Victorian (Letrobe Valley) brown coal. Design based on 5 ton/d pilot unit operational since 1977 at Queensland, Australia. Project now on hold.	N/A

TABLE A-6 (Continued)

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
H-COAL	Breckenridge Project Breckinridge Co., Kentucky	Bechtel Petroleum Inc.	Feasibility and conceptual design complete. 18,000 ton/d Illinois No. 6 to 50,000 bbl/d syncrude. Project reduced to 5,000 bbl/day.	Draft EIS submitted to U.S. and Kentucky EPA Oct. 1981. Final EIS for project to be prepared by Bechtel.
LURGI MKIV DRY-ASH/ LURGI METHANOL SYNTHESIS	Esso Netherlands Project Eemshaven, The Netherlands	Esso Nederland	Construction 17,000 ton/d imported coal to SNG and methanol. Project now on hold.	N/A
LURGI MKIV DRY-ASH/ LURGI METHANOL SYNTHESIS	Nakota Methanol Project Dunn Co., North Dakota	Nakota Co. U.S. DOE	Preliminary engineering by Fluor to be completed mid 1982. 85,000 bbl/d methanol from lignite. Project now on hold.	N/A
GKT/ICI METHANOL SYNTHESIS	Methanol from Peat Project Creswell, North Carolina	Energy Transition Co. (ETCO) Koppers Co. Clark Oil & Refinery Co.	Conceptual design complete for 2,000 ton/d peat to 500 ton/d methanol. Awarded SFC guarantees.	N/A
KBW/ICI METHANOL SYNTHESIS Mobil MTG	Moffat County Project Moffat Co., Colorado	W.R. Grace Co. U.S. DOE	Plant engineering scheduled for 1982 completion. Co-operative agreement with DOE to increase scale to 50,000 bbl/d gasoline output.	N/A
KBW/ICI METHANOL SYNTHESIS Mobil MTG	A-C Valley Project Scrubgrass Township, Venango Co., Pennsylvania	A-C Valley Corp. U.S. DOE	Feasibility and conceptual design complete. 5,000 ton/d to 9,300 bbl/d gasoline and 200 bbl/d liquified propane. SFC guarantees likely mid 1983.	N/A
WESTINGHOUSE AGGLOMERATING PFB METHANOL SYNTHESIS	New England Energy Park Project. Fall River, Massachusetts	EG & G Synfuels Inc. Brooklyn Union Gas Co.	Feasibility study complete. 10,000 ton/d to 17,000 bbl/d methanol and 470 MW combined cycle electric power. SFC guarantees likely by 1983.	N/A
HIGH TEMPERATURE WINKLER/ ICI METHANOL SYNTHESIS	Lignite to Methanol Project Oliver Co., North Dakota	Northern Natural Gas Co. EPRI 16 power companies U.S. DOE	Feasibility study and conceptual design completed. Awarded $3 million by DOE to begin engineering. 75,000 ton/d lignite to 7.5 million gal/d methanol.	Conceptual design by EPRI gives information on waste streams and treatment (EPRI AP-1592).
HIGH TEMPERATURE WINKLER/ ICI METHANOL SYNTHESIS	Beluga Methanol Project Granite Pt., Alaska	Coal Inlet Region Amex Corp.	Conceptual design complete. 54,000 bbl/d methanol from low-S coal. Project on hold.	N/A. See above for general data.

TABLE A-5 (Continued)

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
MODIFIED BERGIUS/I.G. FARBEN/RUHRKOHLE (Catalytic Hard Coal Liquefaction) (Ruhrkohle AG)	Bottrop, North-Rhine Westphalia, West Germany	Ruhrkohle AG Veba Oel AG North-Rhine Westphalia Government	220 ton/d pilot unit operational July 1981. Designed for testing coals.	Liquid and solid wastes sent to nearby coking plant for treatment. In commercial plant would employ light stripping for absorbed gases, Phosam-W ammonia recovery, Chempro phenol recovery, and biox unit. Solid residue gasified in Ruhrkohle/ Ruhrchemie/ Texaco gasifier for hydrogen make-up.
LURGI MKIV DRY ASH/ SYNTHOL (SASOL CATALYST)	SASOL II Secunda (Sasolburg), South Africa	South African Coal, Oil and Gas Corp.	Onstream mid 1981. 25,000 ton/d high-ash sub-bituminous and bituminous coal. Coal fines to power generation (240 MW) and steam generation. Includes petrochemical complex.	Designed for zero-water discharge. Ammonia and phenol recovery followed by conventional AS units and a tertiary treatment.
USSR CATALYTIC LIQUEFACTION	Belhovskaya Pilot Plant Kanshachinsk Coal Mine (Moscow), USSR	Moscow Institute	10 ton/d pilot unit under construction. Catalyst is oil-derived. 300 ton/d pilot unit was scheduled to begin construction 1982 in western Siberia for lignite coals.	N/A
LURGI MKIV DRY-ASH/ SYNTHOL (SASOL CATALYST)	SASOL III Secunda (Sasolburg) South Africa	South Africa Coal, Oil and Gas Corp.	Operational early 1983. Almost exact copy of SASOL II. Coal fines to be tested in Westinghouse gasifier on-site.	See SASOL II project.
HIGH TEMPERATURE WINKLER/ LURGI METHANOL SYNTHESIS (Davy Powergas GmbH)	Rheinbraun Berkenrath Project Berkenrath, W. Germany	Rheinische Braunkohlen-werke AG	Construction began Aug. 1981. 5,500 ton/d lignite to syngas and 1,000 ton/d methanol. Plant approximately 50% complete, Jan. 83.	EPRI study for U.S. plant similar. (EPRI AP-1592).
TEXACO GASIFICATION/LURGI METHANOL SYNTHESIS	Chemicals from Coal Project Kingsport, Tennessee	Tennessee Eastman Co.	Construction began Oct. 1981. Two 900 ton/d modules on local bituminous coals to product acetic anhydride, sulphuric acid and methanol. Plant 80% complete, Jan. 83.	Raw gas water scrubbed for particulate removal and cooling. Mainly sulphur compounds, ammonia and formic acid in sour-water. Physical-chemical treat-ment used. 99.7% sulphur removal from raw gas required. Slagged ash innocuous.
MOBIL MTG (Mobil Oil Corp.)	Maui Gas Field Project New Zealand	New Zealand Liquid Fuels Trust Board. Mobil Oil New Zealand Ltd. Government of New Zealand	Project approved Oct. 1981. Scheduled onstream 1985. 13,000 bbl/d gasoline from natural gas. First commercial-scale Mobile-M Plant.	N/A

TABLE A-6 (Continued)

PROCESS/SUPPLIER	PROJECT TITLE/LOCATION	PARTICIPANTS	STATUS/SCALE	ENVIRONMENTAL INFORMATION
TEXACO GASIFICATION/LURGI METHANOL SYNTHESIS	Mapco Project Carmi, White Co., Illinois	Mapco Synfuels Inc.	Feasibility study complete. 35,000 bbl/d methanol. SFC guarantees likely by 1984.	N/A
WESTINGHOUSE AGGLOMERATING PFB/ICI METHANOL SYNTHESIS	Westinghouse Keystone Project Cambria & Somerset Co., Pennsylvania	Westinghouse Electric Corp. Air Products & Chemicals Amerigas Co. Bethlehem Steel Co. Johnstown Area Regional Industries	Awarded $5 million Oct. 1981 to evaluate 1,800 ton/d high-S coal to 10,500 bbl/d methane in single module plant. Scheduled onstream 1985 at total cost $400 million. Project in design phase.	Energy Impact Associates to perform environmental studies.
LURGI MkIV DRY/ASH/LURGI METHANOL SYNTHESIS/ MOBIL MTG.	Henderson County Project Henderson Co., Kentucky	Tri-State Synfuels Corp. (Texas Eastern, Texas Gas Transmission) Kentucky DOE	Construction date now uncertain. Recently switched to Mobil from Fischer-Tropsch technology. Project tested 22,000 T Kentucky No. 9 coal at SASOL. State funding for 1982/1983.	EIS will be prepared by Radian Corp. based on tests with Kentucky coal at SASOL.
TEXACO GASIFICATION/ICI METHANOL SYNTHESIS /MOBIL MTG.	Baskett Liquefaction Project Baskett, Kentucky	W.R Grace Co. U.S. DOE	Preliminary engineering underway on $7 million DOE grant. 20,000 ton/d high-S agglomerating coal to 50,000 bbl/d gasoline. Project now on hold.	Davis & Moore Engineering and Environmental Consultants selected to prepare final EIS under U.S. Armu Corps of Engineers supervision.
KBW/ICI METHANOL SYNTHESIS/ MOBIL MTG	Oak Ridge Liquefaction Project Oak Ridge, Tennessee	Tennessee Synfuels Associates (Koppers Synfuels Corp., Citgo Synfuels Inc.)	Detailed engineering underway. 5,500 ton/d to 8,500 bbl/d gasoline and 1,500 bbl/d liquified botane and propane. Require SFC guarantees for construction.	Prevention of Significant Deterioration Permit (PSD) issued for plant following EIS submission. D'Appolonia evaluating site for geological, hydroiogical and waste disposal considerations.
LURGI RUHRGAS (Flash Pyrolysis)	Utah Power & Light Pyrolysis Project Huntington Generating Station, Utah	Utah Power & Light Co. Bechtel National	Feasibility study to be complete 1982. 1,200 ton/d bituminous coal to 1,500 bbl/d syncrude and char product for boiler feed/ power generation. Tar upgrading process critical to overall efficiency. Project now on hold.	N/A
MODIFIED BERGIUS/I.G. FARBEN or U.S. DIRECT LIQUEFACTION PROCESS	Kansk-Atchinsk Liqnite Project Siberia, USSR	State Government USSR	USSR to select a technology for plant to be completed by 1985. Multi-billion dollar contract was to be let out by mid to late 1982. Studies now highly uncertain.	N/A

REPORT ON IAWPR VISIT TO SASOL II AND III AT SECUNDA, SOUTH AFRICA APRIL 7, 1982 BY TREVOR BRIDLE, WASTEWATER TECHNOLOGY CENTRE, BURLINGTON, ONTARIO

INTRODUCTION

The SASOL conglomerate comprises of SASOL I at Sasolburg and SASOL II and III at Secunda, in the Northeastern Transvaal, South Africa. SASOL I was built in 1950, SASOL II in 1975, and SASOL III construction commenced in 1979, and is expected to come on line within the next six months. SASOL officials inferred that with all three plants on line, South Africa would not be a net importer of liquid fuels. SASOL II is designed to process 40,000 tonnes of coal per day into 55,000 barrels of liquid fuels. SASOL III is a duplicate of the SASOL II plant, and the estimated total capital cost for SASOL III is $4 billion (1982). All three plants were built by Lurgi and all use the same gasification-liquefaction reforming technology. The range of products produced include gasoline, natural gas, diesel and jet fuels and a host of prime organic chemicals including thylene, alcohols, ketones, and phenols.

Wastewaters from SASOL I are treated prior to discharge to the Vaal River. By contrast the South African Department of Environmental Affairs insisted on no aqueous discharge from SASOL II and III. This had to be done since there are no large water courses to which the complex can discharge. The remainder of this report will address the wastewater and solids handling facilities at SASOL II and III.

General Water Usage and Wastewater Treatment Philosophy

On account of South Africa's limited water resources, SASOL II and III were designed for minimum water usage. For example, wherever possible, use was made of air, rather than water for cooling of process streams. Nonetheless, SASOL II and III utilize raw water at the rate of 44 mgd. To comply with zero-discharge, and yet minimize wastewater

treatment costs, SASOL has separated water supply/treatment into two categories.

The first system comprises the relatively clean non-process cooling water. This cooling water is circulated primarily to the steam and oxygen plants. Blowdown from this system is upgraded by hot lime and sodium softening for use as boiler feed water. Further upgrading, by demineralization, is utilized to feed the waste heat boilers.

The second system comprises the process water and this will be discussed in detail below.

Treatment of Process Wastewater

Process wastewaters comprise of:

1. water that is generated by the manufacturing process
2. spills and storm water
3. blowdown from the process cooling towers, and
4. domestic sewage

These wastewaters are combined and treated via a multitude of unit operations prior to recycle to the process cooling water circuit which operates at about 80 percent recycle (Figure 1).

Design of the wastewater treatment plant was based partly on pilot-scale studies conducted by SASOL Research and also from in-house Lurgi experience. Lurgi were responsible for the entire design, construction and start-up of the SASOL II and III wastewater treatment plants. The estimated capital cost for the SASOL III treatment plant is $\$122 \times 10^6$.

Wastewater Pretreatment

Oily acidic wastewaters are pretreated via API separators. Most other process wastewaters, including the gas liquor are pretreated for oil,

phenol and ammonia recovery (Figure 2). The process involves API separation, sand filtration, solvent extraction and steam stripping. Phenol is recovered using the patented PHENOLSOLVAN process with either butyl acetate of DIPE as the solvent. Phenol recovery is about 98 percent with dihydric phenols being the major effluent species. Ammonia is recovered in a conventional steam distillation column without lime addition.

Secondary Treatment

Pretreated process wastewaters are combined for secondary treatment in a modified activated sludge plant (Figure 3).

The bioplant is segmented into three zones: aerobic, anoxic and aerobic, with recycle from the second aerobic zone to the anoxic zone. This system was designed to provide a "roughing" cell for BOD removal followed by the more conventional predenitrification-nitrification flowsheet. Aeration is supplied by four 5.6 mW blowers connected to "Kenics" type submerged diffusers. The same system is used to provide mixing in the anoxic zone, thus unfortunately, providing unnecessary oxygen. DO in the three zones were claimed to be 2-4, 0 and 1-2, respectively. The total system HRT is 30 hours and control is on a MLVSS basis, the set point being 5,000 - 6,000 mg/L.

Clarification is via two clarifiers in series, with polymer and bentonite added to the second clarifier to enhance solids capture. Sludge is wasted to the sludge handling train at between 150 and 300 kg/h. While SRT is not controlled, the calculated equilibrium SRT, based on average MLVSS and wastage rates is 50 - 100 days.

Typical influent-effluent quality is shown in the table below:

TYPICAL BIOPLANT PERFORMANCE (mg/L)

PARAMETER	INFLUENT	EFFLUENT
COD	1,300	200
TOC	500	50 - 100
Phenol	80	1
TKN	100 - 300	100 - 150
CNS	100	0 - 100
SS		60 - 70
pH	7 - 8	
O & G	20	

The data indicate good removal of COD and phenol, with little or no nitrification/denitrification and variable CNS destruction. To promote nitrification, an additional pre-aerobic stage (12,000 m^3) is being built at a cost of \$8.6 x 10^6.

According to SASOL, a constant feed of domestic sewage is required to prevent bulking. SVI with sewage addition is maintained below 150 cc/g.

Sludge Handling Train

Waste sludge from the secondary clarifier, at about 1 percent is thickened in DAF units. Anionic polymers are used in the DAF unit and a float of about 2 percent TSS is achieved. Dewatering is accomplished using a Humboldt Wedge Solid Bowl centrifuge (drum = 1,120 mm @ 1,100 rpm). Again anionic polymers are used and cake solids of 15 percent are achieved. Total chemical costs for the sludge separation/dewatering train are estimated at \$735,000/month. Dewatered sludge is incinerated in two multiple hearth incinerators. Each comprise 12 hearths of 6m diameter. Synthetic natural gas, produced on-site is the auxiliary fuel. Temperature on the burning hearths is normally controlled between 850 - 900°C. Off-gas is

scrubbed in a high energy venturi scrubber. No stack gas analyses are available. Scrubber water and ash are routed to the main ash dams.

Tertiary Treatment

The unit operations used for tertiary treatment are depicted in Figure 1. Clarified bio effluent is first filtered in dual media (sand/anthracite) filters prior to being subjected to the carbon columns. The only operating data from the carbon columns provided was that COD reductions from 150 to 50 mg/L were achieved. Spent GAS is regenerated on-site in fluid bed regenerators, equipped with off-gas after burners, operated at 1,000°C for 1 - 2 seconds. Major problems are still being experienced with carbon regeneration. Carbon is regenerated every 48 hours and subsequently carbon loss is high (12 - 15 percent).

Effluent from the carbon columns is further upgraded by anion exchange. The original design called for both anion and cation exchange. However, the cation exchangers are not used because the water is too corrosive. The design specifications for recycle water quality is:

COD	50 $mg.L^{-1}$
Cl	9 $mg.L^{-1}$
NH_3-N	20 $mg.L^{-1}$

The only criterion not satisfied is the ammonia level and as mentioned earlier, programs are underway to rectify this problem.

Since the cation exchangers are not working Cr^{6+} (at about 20 mg/L) is added for corrosion inhibition, in cooling water circuit. This results in a Cr^{+6} level of about 1 mg/L in the bio influent. Studies are underway to determine if this has a detrimental effect on bio-performance.

Treatment of Brine Wastes

Strong brine solutions, such as boiler feed water blowdown and ion exchanger regenerants are evaporated in "takketoring" evaporators. However, these old systems are being replaced by RCC evaporators, which are not yet on-line. Evidently, solar evaporation of these highly saline wastes is not practical.

General Comments

The entire system was designed to operate on a negative water balance. However, to date this has been difficult to achieve, and as a result many acres of "balancing ponds" have been built. SASOL has been able to operate at "zero-discharge" with these balancing ponds, and also by using the evaporative capacity of the main ash disposal dams.

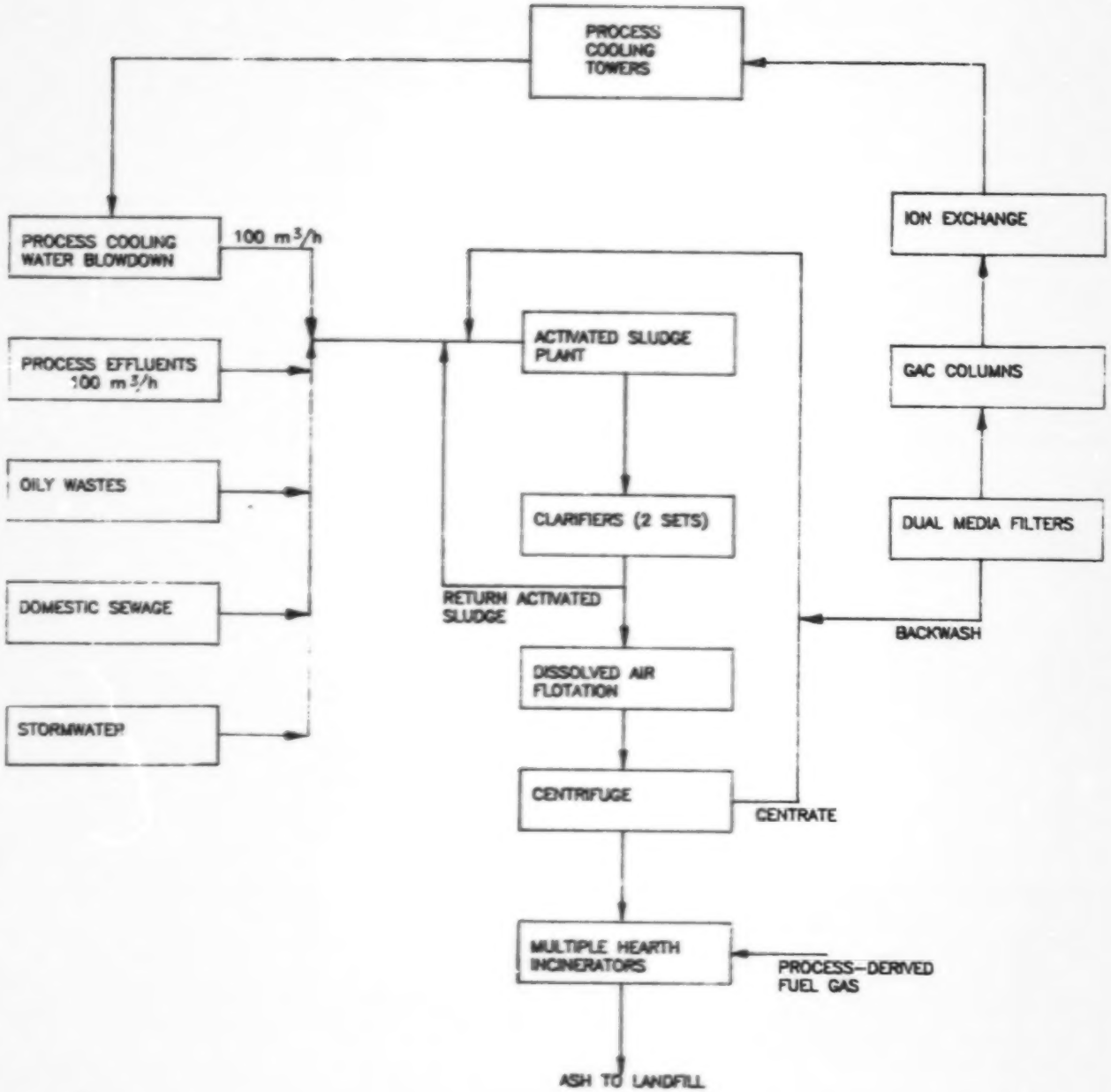

FIGURE 1. SASOL 3: PROCESS WASTEWATER TREATMENT PLANT

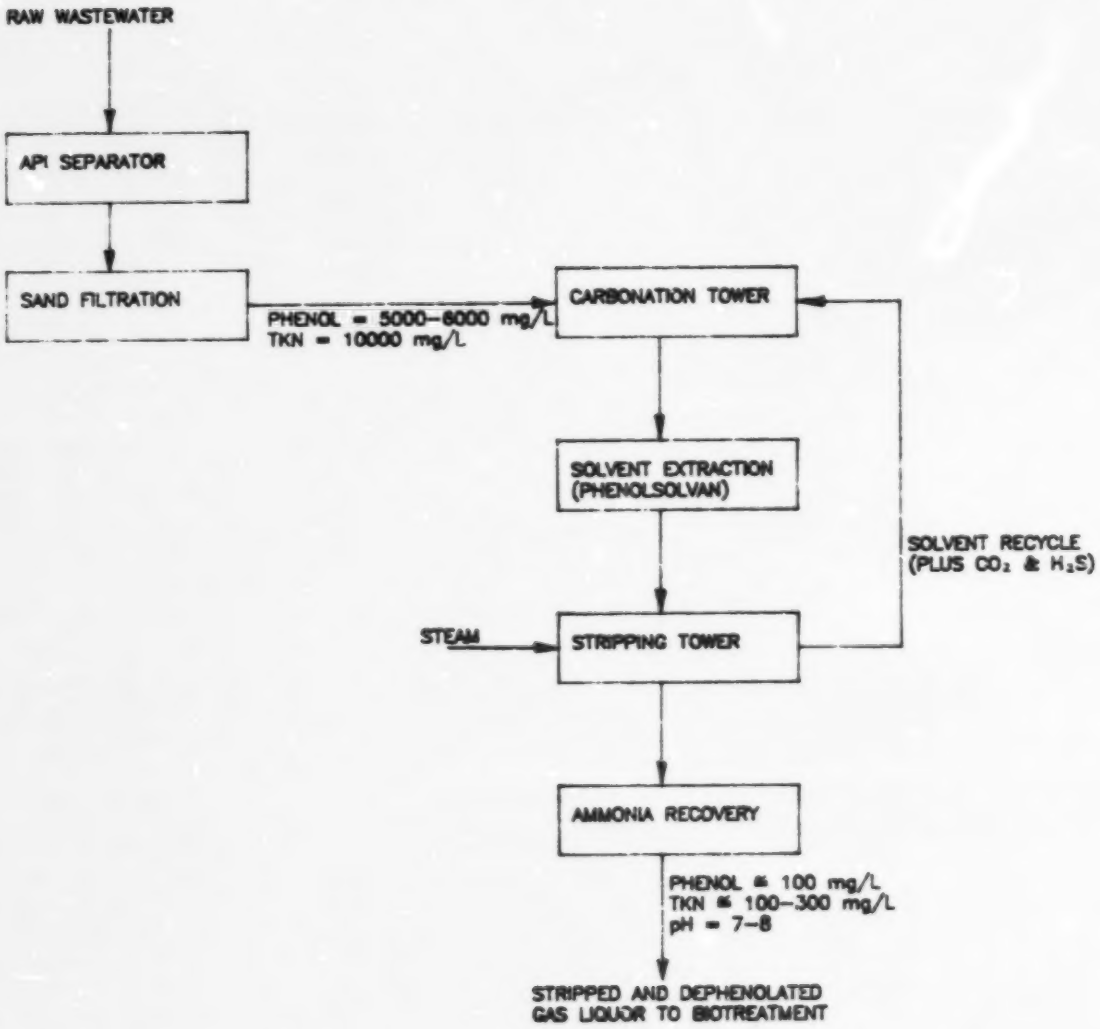

FIGURE 2. PRETREATMENT OF PROCESS WASTEWATERS

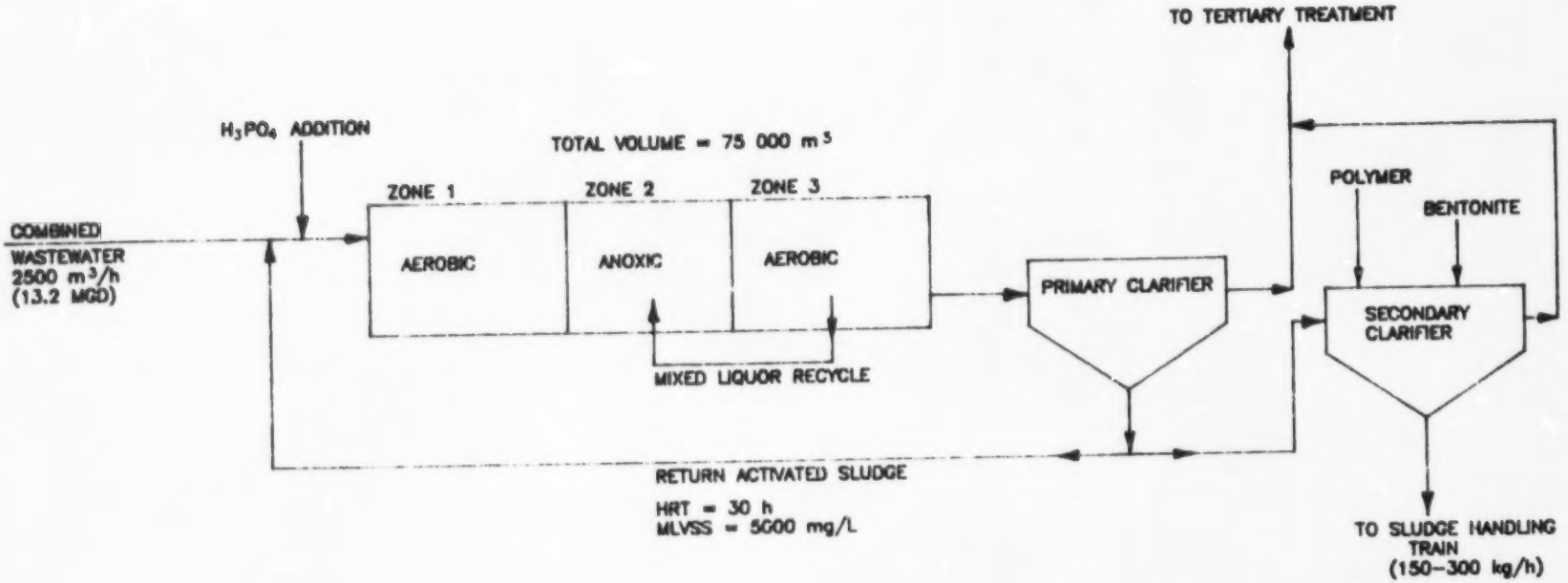

FIGURE 3. ACTIVATED SLUDGE PLANT

POOR

QUALITY

ORIGINAL